Regulatory Impact Analysis for the Proposed 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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TABLE OF CONTENTS

TABLE OF TABLES

TABLE OF FIGURES

EXECUTIVE SUMMARY

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. 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 2020. At the same time, a range of cost-effective technologies and approaches to reduce GHG emissions from these sources are available to the power sector, and multiple projects are in various stages of operation and development—including carbon capture and sequestration/storage (CCS) and co-firing with lower-GHG fuels. Congress has also acted to provide funding and other incentives to encourage the deployment of these technologies to achieve reductions in GHG emissions from the power sector.

In this notice, the EPA is proposing several actions under section 111 of the Clean Air Act (CAA) to reduce the significant quantity of GHG emissions from new and existing fossil fuel-fired EGUs by establishing new source performance standards (NSPS) and emission guidelines that are based on available and cost-effective technologies that directly reduce GHG emissions from these sources. Consistent with the statutory command of section 111, the proposed 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 proposing to update and establish more protective NSPS for GHG emissions from new and reconstructed fossil fuel-fired stationary combustion turbine EGUs that are based on highly efficient generating practices, hydrogen co-firing, and CCS. The EPA is also proposing to establish new emission guidelines for existing fossil fuel-fired steam generating EGUs that reflect the application of CCS and the availability of natural gas co-firing. The EPA is simultaneously proposing to repeal the Affordable Clean Energy (ACE) rule because the emission guidelines established in ACE do not reflect the BSER for steam generating EGUs and are inconsistent with section 111 of the CAA in other respects. To address GHG emissions

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

from existing fossil fuel-fired stationary combustion turbines, the EPA is proposing emission guidelines for large and frequently used existing stationary combustion turbines. Further, the EPA is soliciting comment on how the Agency should approach its legal obligation to establish emission guidelines for the remaining existing fossil fuel-fired combustion turbines not covered by this proposal, including smaller frequently used, and less frequently used, combustion turbines.

Each of the NSPS and emission guidelines proposed here would ensure that EGUs 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 proposed standards and emission guidelines, if finalized, would significantly decrease GHG emissions from fossil fuel-fired EGUs and the associated harms to human health and welfare. Further, the EPA has designed these proposed 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 proposed requirements, a less stringent set of requirements, and a more stringent set of requirements to inform EPA and the public about these projected impacts. With respect to the new source standard, the more stringent scenario differs from the proposal in that it assumes imposition of the second phase of the NSPS in run year 2030, while the proposal and less stringent scenarios assume imposition of the second phase of the NSPS in run year 2035. With regards to the existing source standard, the proposal and more stringent scenarios assume all long-term existing coal-fired steam generating units are subject to 90 percent CCS requirements in 2030, while the less stringent scenario assumes that long-term existing coal-fired steam generating units greater than 700 MW, and plants greater than 2,000 MW are subject to 90 percent CCS requirements, while those units less than 700 MW (and plants less than 2,000 MW) are subject to 40 percent natural gas co-firing requirements. 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 2042, 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, and 2040.

ES.2 Regulatory Requirements

These actions include proposed BSER determinations and accompanying standards of performance for GHG emissions from new and reconstructed fossil fuel-fired stationary combustion turbines, proposed repeal of the ACE Rule, proposed BSER determinations and emission guidelines for existing fossil fuel-fired steam generating units, proposed BSER determinations and emission guidelines for large, frequently used existing fossil fuel-fired stationary combustion turbines, and solicitation for comment on potential BSER options and emission guidelines for existing fossil fuel-fired stationary combustion turbines not otherwise covered by the proposal.

For new and reconstructed fossil fuel-fired combustion turbines, the EPA is proposing to create three subcategories based on the function the combustion turbine serves: a low load ("peaking units") subcategory that consists of combustion turbines with a capacity factor of less than 20 percent; an intermediate load subcategory for combustion turbines with a capacity factor that ranges between 20 percent and a source-specific upper bound that is based on the design efficiency of the combustion turbine; and a base load subcategory for combustion turbines that operate above the upper-bound threshold for intermediate load turbines. This subcategorization approach is similar to the current NSPS for these sources, which includes separate subcategories for base load and non-base load units; however, the EPA is now proposing to subdivide the non-base load subcategory into a low load subcategory and a separate intermediate load subcategory. This revised approach to subcategories is consistent with the fact that utilities and power plant operators are building new combustion turbines with plans to operate them at varying levels of capacity, in coordination with existing and expected energy sources. These patterns of operation are important for the type of controls that the EPA is proposing as the BSER for these turbines, in terms of the feasibility of, emissions reductions that would be achieved by, and cost-reasonableness of, those controls.

For the low load subcategory, the EPA is proposing that the BSER is the use of lower emitting fuels (*e.g.*, natural gas and distillate oil) with standards of performance ranging from 120 lb CO_2/MMBtu to 160 lb CO_2/MMBtu, depending on the type of fuel combusted.[2] For the

[2] In the 2015 NSPS, the EPA referred to clean fuels as fuels with a consistent chemical composition (i.e., uniform fuels) that result in a consistent emission rate of 69 kilograms per gigajoule (kg/GJ) (160 lb CO2/MMBtu). Fuels

intermediate load and base load subcategories, the EPA is proposing an approach in which the BSER has multiple components: (1) highly efficient generation; and (2) depending on the subcategory, use of CCS or co-firing low-GHG hydrogen.

These components of the BSER for the intermediate and base load subcategories form the basis of a standard of performance that applies in multiple phases. That is, affected facilities—which are facilities that commence construction or reconstruction after the date of publication in the *Federal Register* of this proposed rulemaking—must meet the first phase of the standard of performance, which is based exclusively on application of the first component of the BSER (highly efficient generation), by the date the rule is promulgated. Affected sources in the intermediate load and base load subcategories must also meet the second and in some cases third and more stringent phases of the standard of performance, which are based on the continued application of the first component of the BSER and the application of the second and in some cases third component of the BSER. For base load units, the EPA is proposing two pathways as potential BSER—(1) the use of CCS to achieve a 90 percent capture of GHG emissions by 2035 and (2) the co-firing of 30 percent (by volume) low-GHG hydrogen by 2032 and, ramping up to 96 percent by volume low-GHG hydrogen by 2038. These two BSER pathways both offer significant opportunities to reduce GHG emissions but, may be available on slightly different timescales.

More specifically, with respect to the first phase of the standards of performance, the EPA is proposing that the BSER for both the intermediate load and base load subcategories includes highly efficient generating technology (*i.e.*, the most efficient available turbines). For the intermediate load subcategory, the EPA is proposing that the BSER includes highly efficient simple cycle combustion turbine technology with an associated first phase standard of 1,150 lb CO_2/MWh-gross. For the base load subcategory, the EPA is proposing that the BSER includes highly efficient combined cycle technology with an associated first phase standard of 770 lb CO_2/MWh-gross for larger combustion turbine EGUs with a base load rating of 2,000 MMBtu/h or more. For smaller base load combustion turbines (with a base load rating of less than 2,000 MMBtu/h), the proposed associated standard would range from 770 to 900 lb CO_2/MWh-gross

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in this category include natural gas and distillate oil. In this rulemaking, the EPA refers to these fuels as both lower emitting fuels or uniform fuels.

depending on the specific base load rating of the combustion turbine. These standards would apply immediately upon the effective date of the final rule.

With respect to the second phase of the standards of performance, for the intermediate load subcategory, the EPA is proposing that the BSER includes co-firing 30 percent by volume low-GHG hydrogen (unless otherwise noted, all co-firing hydrogen percentages are on a volume basis) with an associated standard of 1,000 lb CO_2/MWh-gross, compliance with which would be required starting in 2032. For the base load subcategory, to elicit comment on both pathways, the EPA is proposing to subcategorize further into base load units that are adopting the CCS pathway and base load units that are adopting the low-GHG hydrogen co-firing pathway. For the subcategory of base load units that are adopting the CCS pathway, the EPA is proposing that the BSER includes the use of CCS with 90 percent capture of CO_2 with an associated standard of 90 lb CO_2/MWh-gross, compliance with which would be required starting in 2035. For the subcategory of base load units that are adopting the low-GHG hydrogen co-firing pathway, the EPA is proposing that the BSER includes co-firing 30 percent (by volume) low-GHG hydrogen with an associated standard of 680 lb CO_2/MWh-gross, compliance with which would be required starting in 2032, and co-firing 96 percent (by volume) low-GHG hydrogen by 2038, which corresponds to a standard of performance of 90 lb CO_2/MWh-gross. In both cases, the second (and sometimes third) phase standard of performance would be applicable to all combustion turbines that were subject to the first phase standards of performance.

With respect to existing coal-fired steam generating units, the EPA is proposing to repeal and replace the existing ACE Rule emission guidelines. The EPA recognizes that, since it promulgated the ACE Rule, the costs of CCS have decreased due to technology advancements as well as new policies including the expansion of the Internal Revenue Code section 45Q tax credit for CCS in the Inflation Reduction Act (IRA); and the costs of natural gas co-firing have decreased as well, due in large part to a decrease in the difference between coal and natural gas prices. As a result, the EPA considered both CCS and natural gas co-firing as candidates for BSER for existing coal-fired steam EGUs.

Based on the latest information available to the Agency on cost, emission reductions, and other statutory criteria, the EPA is proposing that the BSER for existing coal-fired steam EGUs that expect to operate in the long-term is CCS with 90 percent capture of CO_2. The EPA has determined that CCS satisfies the BSER criteria for these sources because it is adequately demonstrated, achieves significant reductions in GHG emissions, and is highly cost-effective.

In response to industry stakeholder input descried in sections I.B.2 and X.C.3 of the preamble, and recognizing that the cost effectiveness of controls depends on the unit's expected operating time horizon, which dictates the amortization period for the capital costs of the controls, the EPA believes it is appropriate to establish subcategories of existing steam EGUs that are based on the operating horizon of the units. The EPA is proposing that for units that expect to operate in the long-term (*i.e.*, those that plan to operate past December 31, 2039), the BSER is the use of CCS with 90 percent capture of CO_2 with an associated degree of emission limitation of an 88.4 percent reduction in emission rate (lb CO_2/MWh-gross basis). As explained in detail in this proposal, CCS with 90 percent capture of CO_2 is adequately demonstrated, cost reasonable, and achieves substantial emissions reductions from these units.

The EPA is proposing to define coal-fired steam generating units with medium-term operating horizons as those that (1) operate after December 31, 2031, (2) have elected to commit to permanently cease operations before January 1, 2040, (3) elect to make that commitment federally enforceable and continuing by including it in the state plan, and (4) do not meet the definition of near-term operating horizon units. For these medium-term operating horizon units, the EPA is proposing that the BSER is co-firing 40 percent natural gas on a heat input basis with an associated degree of emission limitation of a 16 percent reduction in emission rate (lb CO_2/MWh-gross basis). While this subcategory is based on a 10-year operating horizon (*i.e.*, January 1, 2040), the EPA is specifically soliciting comment on the potential for a different operating horizon between 8 and 10 years to define the threshold date between the definition of medium-term and long-term coal-fired steam generating units (*i.e.*, January 1, 2038 to January 1, 2040), given that the costs for CCS may be reasonable for units with amortization periods as short as 8 years. For units with operating horizons that are imminent-term, i.e., those that (1) have elected to commit to permanently cease operations before January 1, 2032, and (2) elect to make that commitment federally enforceable and continuing by including it in the state plan, the EPA is proposing that the BSER is routine methods of operation and maintenance with an associated degree of emission limitation of no increase in emission rate (lb CO_2/MWh-gross basis). The EPA is proposing the same BSER determination for units in the near-term operating horizon subcategory, i.e., units that (1) have elected to commit to permanently cease operations by December 31, 2034, as well as to adopt an annual capacity factor limit of 20 percent, and (2) elect to make both of these conditions federally enforceable by including them in the state plan. The EPA is also soliciting comment on a potential BSER based on low levels of natural gas co-firing for units in these last two subcategories.

The EPA is also proposing emission guidelines for existing natural gas-fired and oil-fired steam generating units. Recognizing that virtually all of these units have limited operation, the EPA is, in general, proposing that the BSER is routine methods of operation and maintenance with an associated degree of emission limitation of no increase in emission rate (lb CO_2/MWh-gross).

The EPA is also proposing emission guidelines for large (*i.e.*, greater than 300 MW), frequently operated (*i.e.*, with a capacity factor of greater than 50 percent), existing fossil fuel-fired stationary combustion turbines. Because these existing combustion turbines are similar to new stationary combustion turbines, the EPA is proposing a BSER that is similar to the BSER for new base load combustion turbines. The EPA is not proposing a first phase efficiency-based standard of performance; but the EPA is proposing that BSER for these units is based on either the use of CCS by 2035 or co-firing of 30 percent (by volume) low-GHG hydrogen by 2032 and co-firing 96 percent low-GHG hydrogen by 2038.

For the emission guidelines for existing fossil fuel-fired steam generating units and large, frequently operated fossil fuel-fired combustion turbines, the EPA is also proposing state plan requirements, including submittal timelines for state plans and methodologies for determining presumptively approvable standards of performance consistent with BSER. This proposal also addresses how states can implement the remaining useful life and other factors (RULOF) provision of CAA section 111(d) and how states can conduct meaningful engagement with impacted stakeholders. Finally, the EPA is proposing to allow states to include trading or averaging in state plans so long as they demonstrate equivalent emissions reductions, and this proposal discusses considerations related to the appropriateness of including such compliance flexibilities.

ES.3 Baseline and Analysis Years

The impacts of proposed 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 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 proposed 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 post-IRA IPM 2022 reference case") 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.

This RIA evaluates the benefits, costs, and certain impacts of compliance with three illustrative scenarios: the proposal, a less stringent scenario, and a more stringent scenario, 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 2042 from the perspective of 2024, using both three percent and seven percent discount rates. 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, and 2040. 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 2042. The year 2028 is the first year of detailed power sector modeling for this RIA and approximates when the regulatory impacts of the proposed 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 2042, as this is the last year that may be represented with the analysis conducted for the specific year of 2040. 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.

The modeling of the illustrative proposal scenario that is discussed in Sections 3 through 7 of this RIA (and Sections 0.4 through 0.9 of the Executive Summary) includes all aspects of the proposed 111(d) requirements for existing fossil fuel-fired steam generating units and most aspects of the proposed 111(b) requirements for new and reconstructed stationary combustion turbines. However, it does not reflect the proposed 111(d) requirements for existing stationary combustion turbines or one additional component of the 111(b) requirements (for new base load combustion turbines in the hydrogen co-firing subcategory, the third phase standard based on co-firing 96 percent low-GHG hydrogen by 2038). For these additional measures, EPA performed a spreadsheet-based analysis of regulatory impacts that is discussed in Section 8 of this RIA (and in Section ES.10 of the Executive Summary).

ES.4 Emissions Impacts

The emissions impacts presented in this RIA are from years 2028, 2030, 2035, and 2040 and are based on Integrated Planning Model (IPM) projections.[3] Table ES-1 presents the estimated impact on power sector emissions in the contiguous U.S. resulting from compliance with the proposed rules as modeled by the illustrative proposal scenario. The projections indicate that the illustrative proposal scenario and less stringent scenario result in national emission reductions of CO_2, direct $PM_{2.5}$, NO_X, and SO_2 throughout the year for each of the snapshot years analyzed. The projections indicate that the more stringent scenario results in national

[3] Section ES.4 pertains to the analysis of the proposed standards for new natural gas-fired EGUs and for existing coal-fired EGUs. Please see Section ES.10 for impact analysis of the proposed standards for existing natural gas-fired EGUs and the third phase of the proposed standards for new natural gas-fired EGUs.

emissions reductions of CO_2 and SO_2 throughout the year for the snapshot years analyzed, but national emission increases of NO_X in 2028, both annually and during the ozone season under the more stringent scenario. Under the more stringent scenario, hydrogen co-firing requirements for new NGCC builds are in effect in the 2030 run year as compared to 2035 under the proposal and less stringent scenarios. As a result, anticipating weaker economics for new NGCC builds, there are 0.8 GW fewer NGCC additions and 3.3 GW greater NGCT additions projected relative to the baseline. This in turn results in slightly higher NO_X emissions in 2028. In 2030, requirements on existing sources and new sources drive down total NO_X emissions below baseline levels. Under the illustrative proposal scenario CO_2 emission reductions over the 2028 to 2042 timeframe are estimated to be 617 million metric tons. Under the less and more stringent illustrative scenarios, cumulative CO_2 emission reductions over the 2028 to 2042 timeframe are estimated to be 578 million metric tons and 685 million metric tons, respectively.[4]

Table ES-1 Projected EGU Emissions and Emissions Changes for the Three Illustrative Scenarios for 2028, 2030, and 2035, and 2040 [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)
Proposal					
2028	-10	-7	-3	-12	-1
2030	-89	-64	-22	-107	-6
2035	-37	-21	-7	-41	-1
2040	-24	-13	-4	-30	-1
Less Stringent					
2028	-9	-7	-3	-9	-1
2030	-83	-61	-20	-99	-5
2035	-35	-20	-7	-38	-1
2040	-22	-12	-4	-27	-1
More Stringent					
2028	0	3	1	-4	0
2030	-107	-61	-20	-114	-5
2035	-42	-22	-7	-41	-2
2040	-23	-13	-4	-30	-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.

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

ES.5 Compliance Costs

The compliance cost estimates presented in this RIA are based on IPM projections, and supplemented with cost estimates for MR&R.[5] As described previously, this RIA evaluates three illustrative scenarios: the proposal, a less stringent scenario, and a more stringent scenario. The more stringent scenario differs from the proposal in that it assumes imposition of the second phase of the NSPS requirements on new sources in run year 2030, while the proposal and less stringent scenarios assume imposition of the second phase of the NSPS requirements in run year 2035.[6] The proposal and more stringent scenarios assume all long-term existing coal-fired steam generating units (i.e. units that do not have a firm retirement date prior to run year 2040) are subject to 90 percent CCS requirements in 2030, while the less stringent scenario assumes that long-term existing coal-fired steam generating units greater than 700 MW, and plants greater than 2,000 MW are subject to 90 percent CCS requirements, while those units less than 700 MW (and plants less than 2,000 MW) are subject to 40 percent natural gas co-firing requirements in 2030.

Table ES-2 below summarizes the present value (PV) and equivalent annualized value (EAV) of the total national compliance cost estimates[7] for the illustrative proposal scenario and the less and more stringent scenarios. We present the PV of the costs over the 19-year period of 2024 to 2042. 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.

IPM estimates compliance costs incurred by regulated firms, but because of the availability of subsidy payments, there are additional real resource costs to the economy outside of the regulated sector. IPM provides EPA's best estimate of the costs of the proposed rules to the electricity sector and related energy sectors (i.e., natural gas, coal mining). To estimate the

[5] Section ES.5 pertains to the analysis of the proposed standards for new natural gas-fired EGUs and for existing coal-fired EGUs. Please see Section ES.10 for impact analysis of the proposed standards for existing natural gas-fired EGUs and the third phase of the proposed standards for new natural gas-fired EGUs.

[6] Run year 2030 is mapped to calendar years 2029-2031, while run year 2035 is mapped to calendar years 2032-2037.

[7] 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 Section 3.7 for further discussion of the differences between compliance costs and social costs.

social costs for the economy as a whole, EPA has used information from IPM as an input into the 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. See Section 5.2 and Appendix B for more discussion on estimates of private and social costs. EPA requests comment on the SAGE analysis in section XIV(C) of the preamble to these proposed rules.

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

	3% Discount Rate		7% Discount Rate	
	PV	**EAV**	**PV**	**EAV**
Proposal	14	0.95	10	0.98
Less Stringent	13	0.93	10	0.96
More Stringent	10	0.70	7.5	0.73

Note: Values have been rounded to two significant figures.

Projected compliance costs are similar across the scenarios. Costs under the more stringent scenario are projected to be lower than under the less-stringent scenario and the proposal in 2030. This is due to the assumption that when the second phase of the NSPS is active, hydrogen costs (represented exogenously in the modeling) are assumed to be $0.5/kg rather than $1/kg otherwise. For details on the hydrogen modeling assumptions used in this analysis, please see Section 3 of this RIA.[8] Under the proposal and less stringent scenarios, the second phase of the NSPS is assumed to be active in 2035, while under the more stringent scenario, the second phase of the NSPS is assumed to be active in 2030. The lower input hydrogen fuel price in 2030 under the more stringent scenario therefore drives total compliance costs lower than under the other two scenarios. EPA solicits comments in section XIV(B) of the preamble on its cost estimation generally.

ES.6 Benefits

The proposed rules are expected to reduce emissions CO_2, NO_X, $PM_{2.5}$, and SO_2 nationally. This section reports the estimated monetized climate and health benefits associated with

[8] EPA is continuing to evaluate the evolving literature on the economics of hydrogen, including the DOE's Pathways to Commercial Liftoff: Clean Hydrogen report (available at: https://liftoff.energy.gov/wp-content/uploads/2023/03/20230320-Liftoff-Clean-H2-vPUB-0329-update.pdf)

emission reductions for each of the three illustrative scenarios described in prior sections and discusses other unquantified benefits.[9]

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 proposed rules. Climate benefits from reducing emissions of CO_2 are monetized using estimates of the social cost of carbon (SC-CO_2). 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 national emissions of direct $PM_{2.5}$, NO_X, and SO_2 throughout the year. 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 proposed 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

[9] Section ES.6 pertains to the analysis of the proposed standards for new natural gas-fired EGUs and for existing coal-fired EGUs. Please see Section ES.10 for impact analysis of the proposed standards for existing natural gas-fired EGUs and the third phase of the proposed standards for new natural gas-fired EGUs.

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 proposed 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, 2023). 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 proposal scenario and the more and less stringent scenarios.

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

	All Benefits Calculated using 3% Discount Rate					
	Climate Benefits [b]		$PM_{2.5}$ and O_3-related Health Benefits [c]		Total Benefits [d,e]	
	PV	EAV	PV	EAV	PV	EAV
Proposal	30	2.1	68	4.8	98	6.9
Less Stringent	28	2.0	58	4.1	87	6.0
More Stringent	34	2.4	65	4.6	99	6.9
	Climate Benefits Calculated using 3% 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,e]	
	PV	EAV	PV	EAV	PV	EAV
Proposal	30	2.1	44	4.3	74	6.4
Less Stringent	28	2.0	38	3.7	66	5.7
More Stringent	34	2.4	42	4.0	76	6.4

[a] Values have been rounded to two significant figures. Rows may not appear to add correctly due to rounding.
[b] Climate benefits in this table are based on estimates of the SC-CO_2 at a 3 percent discount rate.
[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.
[d] Several categories of benefits remain unmonetized and are thus not reflected in the table. Non-monetized benefits include important climate, health, welfare, and water quality benefits.
[e] For discussions of the uncertainty associated with these health benefits estimates, see Section 4.3.8. See Section 4.2 for a discussion of the uncertainties associated with the climate benefit estimates.

ES.7 Economic Impacts

As a result of the compliance costs incurred by the regulated sector, these proposed actions have economic and energy market implications. The energy impact estimates presented here reflect EPA's illustrative analysis of the proposed rules.[10] States are afforded flexibility to implement the proposed 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, and 2040 for the illustrative proposal scenario, relative to the baseline. These results are EPA’s best estimate of possible compliance

[10] Section ES.7 pertains to the analysis of the proposed standards for new natural gas-fired EGUs and for existing coal-fired EGUs. Please see Section ES.10 for impact analysis of the proposed standards for existing natural gas-fired EGUs and the third phase of the proposed standards for new natural gas-fired EGUs.

pathways with the policy. 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 Proposal Scenario Relative to the Baseline

	2028	2030	2035	2040
Retail electricity prices	-1%	2%	0%	0%
Average price of coal delivered to power sector	-1%	0%	2%	2%
Coal production for power sector use	-2%	-40%	-23%	-15%
Price of natural gas delivered to power sector	0%	9%	-2%	-3%
Price of average Henry Hub (spot)	0%	10%	-2%	-2%
Natural gas use for electricity generation	0%	8%	-1%	-2%

These and other energy market impacts are discussed more extensively in Section 3 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 proposed rules, electricity – is used as an input in the production of other goods. It may also affect upstream industries that supply goods and services to the sector, along with labor and capital markets, as these suppliers alter production processes in response to changes in factor prices. Changes in firm and household behavior in response to the proposed rules could also interact with pre-existing distortions, such as taxes, resulting in additional social costs. In addition, households may change their demand for particular goods and services due to changes in the price of electricity and other final goods prices. Economy-wide models - and, more specifically, computable general equilibrium (CGE) models - are analytical tools that can be used to evaluate the broad impacts of a regulatory action. A CGE-based approach to cost estimation concurrently considers the effect of a regulation across all sectors in the economy, including interactions and feedbacks between them.

In 2015, EPA established a Science Advisory Board (SAB) panel to consider the technical merits and challenges of using economy-wide models to evaluate costs, benefits, and economic impacts in regulatory analysis. In its final report, the SAB recommended that EPA begin to integrate CGE modeling into applicable regulatory analysis to offer a more comprehensive assessment of the effects of air regulations (U.S. EPA Science Advisory Board, 2017). In response to the SAB's recommendations, EPA developed a new CGE model for the U.S. economy called SAGE designed for use in regulatory analysis. A second SAB panel performed a peer review of SAGE, and the review concluded in 2020 (U.S. EPA Science Advisory Board, 2020).

EPA used SAGE to evaluate the economy-wide social costs and economic impacts of these proposed rules. The annualized social costs estimated in SAGE are approximately 35 percent larger than the partial equilibrium private compliance costs (less taxes and transfers) derived from IPM. This is consistent with general expectations based on the empirical literature (e.g., Marten et al., 2019). However, the social cost estimate reflects the combined effect of the proposed rules' requirements and interactions with IRA subsidies for specific technologies that are expected to see increased use in response to the proposed rules. We are not able to identify their relative roles at this time. A detailed discussion of the social costs and distributional impacts of the proposed rules is contained in Appendix B of this RIA. Section XIV(C) of the preamble to this proposal solicits comment on this economy-wide analysis presented in the RIA appendix.

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 proposed actions are discussed more extensively in Section 5 of the RIA.

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.[11] For the rule, we quantitatively evaluate 1) the proximity of affected facilities to potentially vulnerable and/or overburdened populations for consideration of local pollutants impacted by 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 three illustrative scenarios across different demographic groups on the basis of race, ethnicity, poverty status, employment status, health insurance status, age, sex, educational attainment, and degree of linguistic isolation (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 depends on mutually exclusive assumptions, was performed to answer separate questions, and is associated with unique limitations and uncertainties.

Baseline demographic proximity analyses provide information as to whether there may be potential EJ concerns associated with environmental stressors, 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 10 km and 50 km of the following three sets of sources: 1) all 140 coal plants with units potentially subject to the proposed 111 rule, 2) three coal plants retiring by January 1, 2032, with units potentially subject to the proposed 111 rules, and 3) 19 coal plants retiring between January 1, 2032, to January 1, 2040, with units potentially subject to the proposed 111 rules. The proximity analysis of the full population of potentially affected units greater than 25 MW indicated that the demographic percentages of the population within 10 km and 50 km of the facilities are relatively similar to the national averages. The proximity analysis of the 19 units that will retire from January 1, 2032, to January 1, 2040 (a subset of the total 140 units) found that the percent of the population within 10 km that is African American is higher than the

[11] Section ES.8 pertains to the analysis of the proposed standards for new natural gas-fired EGUs and for existing coal-fired EGUs. Please see Section ES.10 for impact analysis of the proposed standards for existing natural gas-fired EGUs and the third phase of the proposed standards for new natural gas-fired EGUs.

national average. The proximity analysis for the 3 units that will retire by January 1, 2032 (a subset of the total 140 units) found that for both the 10 km and 50 km populations the percent of the population that is American Indian for one facility is significantly above the national average, the percent of the population that is Hispanic/Latino for another facility is substantially above the national average, and all three facilities were well above the national average for both the percent below the poverty level and the percent below two times the poverty level.

Because the pollution impacts that are the focus of these rules may occur downwind from affected facilities, ozone and $PM_{2.5}$ exposure analyses that evaluate demographic variables are better able to evaluate any potentially disproportionate pollution impacts of this rulemaking. The baseline $PM_{2.5}$ and ozone 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 6.5). Baseline ozone and $PM_{2.5}$ exposure analyses show that certain populations, such as Hispanics, Asians, those linguistically isolated, and those less educated may experience disproportionately higher ozone and $PM_{2.5}$ exposures as compared to the national average. Black populations may also experience disproportionately higher $PM_{2.5}$ concentrations than the reference group, and American Indian populations 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 (question 1).

Finally, we evaluate how the three illustrative scenarios of this proposed rulemaking are expected to differentially impact demographic populations, informing questions 2 and 3 from EPA's EJ Technical Guidance with regard to ozone and $PM_{2.5}$ exposure changes. We infer that baseline disparities in the ozone and $PM_{2.5}$ concentration burdens are likely to remain after implementation of the regulatory action or alternatives under consideration. This is due to the small magnitude of the concentration changes associated with this rulemaking across population demographic groups, relative to the magnitude of the baseline disparities (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 illustrative scenarios analyzed will not likely mitigate or exacerbate ozone exposure disparities for the population groups evaluated, ozone exposure disparities may be exacerbated for some population groups analyzed in 2030 under all illustrative scenarios. However, the extent to which disparities may be exacerbated 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 this proposal 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.

ES.9 Comparison of Benefits and Costs

In this RIA, the regulatory impacts are evaluated for the specific snapshot years of 2028, 2030, 2035, and 2040, and MR&R costs are estimated for all years in the 2024 to 2042 timeframe.[12] Comparisons of benefits to costs for the snapshot years of 2028, 2030, 2035, and 2040 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 2042 from the perspective of 2024, using both a three percent and seven percent discount rate as directed by OMB's Circular A-4. 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 2042, would yield a sum equivalent to the PV. The EAV represents the value of a typical cost or benefit for each year of the analysis, in contrast to the year-specific estimates reported in the costs and benefits sections of this RIA.

The comparison of benefits and costs in PV and EAV terms for the illustrative proposal scenario and less and more stringent scenarios can be found in Table ES-5. Estimates in the tables are presented as rounded values.

[12] Section ES.9 pertains to the analysis of the proposed standards for new natural gas-fired EGUs and for existing coal-fired EGUs. Please see Section ES.10 for impact analysis of the proposed standards for existing natural gas-fired EGUs and the third phase of the proposed standards for new natural gas-fired EGUs.

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

	All Values Calculated using 3% Discount Rate							
	Climate Benefits [b]		$PM_{2.5}$ and O_3-related Health Benefits [c]		Compliance Costs		Net Benefits [d]	
Regulatory Option	**PV**	**EAV**	**PV**	**EAV**	**PV**	**EAV**	**PV**	**EAV**
Proposed	30	2.1	68	4.8	14	0.95	85	5.9
Less Stringent	28	2.0	58	4.1	13	0.93	73	5.1
More Stringent	34	2.4	65	4.6	10	0.70	89	6.2
	Climate Benefits Calculated using 3% Discount Rate, Compliance Costs and Health Benefits Calculated using 7% Discount Rate							
	Climate Benefits [b]		$PM_{2.5}$ and O_3-related Health Benefits [c]		Compliance Costs		Net Benefits [d]	
Regulatory Option	**PV**	**EAV**	**PV**	**EAV**	**PV**	**EAV**	**PV**	**EAV**
Proposed	30	2.1	44	4.3	10	0.98	64	5.4
Less Stringent	28	2.0	38	3.7	10	0.96	56	4.7
More Stringent	34	2.4	42	4.0	7.5	0.73	68	5.7

[a] Values have been rounded to two significant figures. Rows may not appear to add correctly due to rounding.
[b] Climate benefits in this table are based on estimates of the SC-CO_2 at a 3 percent discount rate.
[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] Several categories of benefits remain unmonetized and are thus not reflected in the table. Non-monetized benefits include important climate, health, welfare, and water quality benefits.

As discussed in Section 4 of this RIA, the monetized benefits estimates provide an incomplete overview of the beneficial impacts of the proposal. 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 proposed rules are not quantified or monetized. EPA anticipates that taking non-monetized effects into account would show the proposals 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 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 proposals exceed the costs by billions of dollars annually.

We also note that the RIA follows EPA's historic 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 Appendix B of this RIA, EPA has also included an economy-wide analysis that considers additional facets of the economic response to the proposed rules, including the full resource requirements of the expected compliance pathways, some of which are paid for through subsidies in the partial equilibrium analysis. The social cost estimates in the economy-wide analysis and discussed in Appendix B are still far below the projected benefits of the proposed rules.

ES.10 Proposed 111(d) Standards for Existing Natural Gas-Fired EGUs and Third Phase of the Proposed 111(b) Standards for New Natural Gas-Fired EGUs

ES.10.1 Introduction

The existing source performance standards modeled using IPM did not include the proposed requirements on existing natural gas-fired combined cycle (NGCC) units as summarized in Table ES-6. To estimate the regulatory impacts of these proposed requirements, EPA performed a spreadsheet-based analysis using the model output of each of the illustrative scenarios described earlier to produce a range of possible outcomes. This analysis therefore does not include any additional IPM modeling, and does not identify the least-cost compliance pathways for affected sources given the standards modeled. As such, the results from this analysis could differ from the compliance behavior that would be projected under incremental IPM modeling. For details, please see Section 8.6.

Table ES-6 GHG Mitigation Measures for Existing NGCC Units under the Illustrative Proposal, More Stringent and Less Stringent Scenarios

Affected EGUs	GHG Mitigation Measure	GHG Mitigation Measure
Natural Gas fired Combined Cycle Units > 300 MW and operating > 50% capacity factor in run year 2035 with online year of 2025 or earlier	Co-fire 30% by volume hydrogen in run year 2035, and 96% by volume hydrogen in run year 2040	CCS with 90 percent capture of CO_2, starting in run year 2035

The new source performance standards modeled using IPM also did not include additional requirements on new NGCC units—specifically, the proposed requirements for new base load combustion turbines in the hydrogen co-firing subcategory to comply with a third phase standard based on co-firing 96 percent low-GHG hydrogen by run year 2040— as summarized in Table ES-7. To estimate the impact of these proposed requirements, EPA performed a spreadsheet-based analysis using the model output of each of the illustrative scenarios to produce a range of possible outcomes as outlined in Section 8 of the RIA. As is the case for the analysis of existing natural gas-fired combined cycle units, this analysis also does not include any additional IPM modeling, and does not identify the least-cost compliance pathways for affected sources given the standards modeled. As such, the results from this analysis could differ from the compliance behavior that would be projected under incremental IPM modeling. For details, please see Section 8.6.

Table ES-7 GHG Mitigation Measures for New NGCC Units under the Illustrative Proposal, More Stringent and Less Stringent Scenarios

Affected EGUs	GHG Mitigation Measure
Natural Gas Combined Cycle Units with online year after 2025 that operate at > 50% capacity factor	Co-fire 96% by volume hydrogen in run year 2040 onwards, or install CCS.

ES.10.2 Emissions Impacts

Based on the analysis outlined above, EPA estimated the change in CO_2 emissions from the additional measures selected to the outcomes under the three illustrative scenarios (the IPM-modeled aspects of the proposal and less and more stringent scenarios, for existing fossil-fuel fired steam generating units and new and reconstructed stationary combustion turbines)). These results are summarized in Table ES-8 and Table ES-9 below. Because this additional analysis used the IPM outputs from the illustrative scenarios as its baseline, these results do not capture the potential for interactive effects between the additional measures and the IPM-modeled measures (e.g., the potential that establishing 111(d) requirements for existing natural gas-fired EGUs could affect the compliance approaches undertaken by other EGUs or lead to different shifts in the overall generation mix than those reflected in the IPM outputs). EPA did not estimate changes in emissions of other non-CO_2 air pollutants.

Table ES-8 and Table ES-9 present CO_2 change results for low and high ends of a range based on different assumptions in how many model existing plants install CCS and how many model new plants increase hydrogen co-firing.

Table ES-8 Estimated Changes in Power Sector Emissions from the Proposed 111(d) for Existing Natural Gas-fired EGUs for the Three Illustrative Scenarios

Annual CO_2 (million metric tons)	Proposal		Less Stringent		More Stringent	
	Low	High	Low	High	Low	High
2028	0	0	0	0	0	0
2030	0	0	0	0	0	0
2035	-20	-37	-20	-37	-20	-37
2040	-19	-37	-19	-37	-19	-37

Table ES-9 Estimated Changes in Power Sector Emissions from the Third Phase of the Proposed 111(b) for New Natural Gas-fired EGUs for the Three Illustrative Scenarios

Annual CO_2 (million metric tons)	Proposal		Less Stringent		More Stringent	
	Low	High	Low	High	Low	High
2028	0	0	0	0	0	0
2030	0	0	0	0	0	0
2035	0	0	0	0	0	0
2040	-0.22	-2.5	-0.20	-2.5	-2.21	-4.2

ES.10.3 Cost Impacts

Table ES-10 summarizes the present value (PV) and equivalent annualized value (EAV) of the total national compliance cost estimate for the existing gas standard and the third phase of the new source standard under the illustrative proposal scenario, less stringent and more stringent scenarios. These estimates are derived using the spreadsheet-based analysis just described and do not include any additional IPM modeling.

Similar levels of projected costs are estimated under the proposal and less stringent scenario, reflecting similar levels of existing and new gas operation under the illustrative proposal and less stringent scenarios. Costs under the more stringent scenario (where the second phase standards for new NGCC builds are in effect in the 2030 run year as compared to 2035) are estimated to be higher than under the proposal and less stringent scenario, driven primarily by higher levels of estimated new source hydrogen burn.

Table ES-10 Present Values and Equivalent Annualized Values of Compliance Cost Estimates for the Proposed 111(d) for Natural Gas-fired EGUs and Third Phase of the Proposed 111(b) for Natural Gas-fired EGUs (discounted to 2024, billion 2019 dollars)

	3% Discount Rate				7% Discount Rate			
	PV		EAV		PV		EAV	
	Low	High	Low	High	Low	High	Low	High
Proposal	5.7	10	0.40	0.70	3.5	6.2	0.34	0.60
Less Stringent	5.7	10	0.40	0.70	3.5	6.2	0.34	0.60
More Stringent	6.2	10	0.44	0.73	3.8	6.4	0.37	0.62

Note: Values have been rounded to two significant figures.

ES.10.4 Climate Benefits

As discussed in Section ES.6.1, there will be important climate benefits associated with the estimated CO_2 emissions reductions expected from these proposed rules. Climate benefits from reducing emissions of CO_2 are monetized using estimates of the social cost of carbon (SC-CO_2). See Section 4.2 of this RIA for more discussion of the approach to monetization of the climate benefits associated with these rules. See Section 8.4 of this RIA for more discussion about the specific estimated climate benefits associated with the proposed 111(d) for natural gas-fired EGUs and the third phase of the proposed 111(b) for natural gas-fired EGUs.

Table ES-11 Present Values and Equivalent Annualized Values of Monetized Climate Benefit Estimates for the Proposed 111(d) for Natural Gas-fired EGUs and Third Phase of the Proposed 111(b) for Natural Gas-fired EGUs (discounted to 2024, billion 2019 dollars)[a,b,c]

	3% Discount Rate			
	PV		EAV	
	Low	High	Low	High
Proposal	10	20	0.70	1.4
Less Stringent	10	20	0.71	1.4
More Stringent	11	20	0.74	1.4

[a] Values have been rounded to two significant figures. Rows may not appear to add correctly due to rounding.
[b] Climate benefits in this table are based on estimates of the SC-CO_2 at a 3 percent discount rate.
[c] Several categories of benefits remain unmonetized and are thus not reflected in the table. Non-monetized benefits include important climate, health, welfare, and water quality benefits.

ES.11 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.[13] 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. 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 2020. At the same time, a range of cost-effective technologies and approaches to reduce GHG emissions from these sources are available to the power sector, and multiple projects are in various stages of operation and development—including carbon capture and sequestration/storage (CCS) and co-firing with lower-GHG fuels. Congress has also acted to provide funding and other incentives to encourage the deployment of these technologies to achieve reductions in GHG emissions from the power sector.

In this notice, the EPA is proposing several actions under section 111 of the Clean Air Act (CAA) to reduce the significant quantity of GHG emissions from new and existing fossil fuel-fired EGUs by establishing new source performance standards (NSPS) and emission guidelines that are based on available and cost-effective technologies that directly reduce GHG emissions from these sources. Consistent with the statutory command of section 111, the proposed 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 for the purpose of improving the emissions performance of the covered EGUs.

Specifically, the EPA is proposing to update and establish more protective NSPS for GHG emissions from new and reconstructed fossil fuel-fired stationary combustion turbine EGUs that are based on highly efficient generating practices, hydrogen co-firing, and CCS. The EPA is also proposing to establish new emission guidelines for existing fossil fuel-fired steam generating EGUs that reflect the application of CCS and the availability of natural gas co-firing. The EPA is simultaneously proposing to repeal the Affordable Clean Energy (ACE) rule because the emission guidelines established in ACE do not reflect the BSER for steam generating EGUs

[13] 74 FR 66496 (December 15, 2009).

and are inconsistent with section 111 of the CAA in other respects. To address GHG emissions from existing fossil fuel-fired stationary combustion turbines, the EPA is proposing emission guidelines for large and frequently used existing stationary combustion turbines. Further, the EPA is soliciting comment on how the Agency should approach its legal obligation to establish emission guidelines for the remaining existing fossil fuel-fired combustion turbines not covered by this proposal, including smaller frequently used existing fossil fuel-fired combustion turbine EGUs and less frequently used existing fossil fuel-fired combustion turbines.

Each of the NSPS and emission guidelines proposed here would ensure that EGUs 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 proposed standards and emission guidelines, if finalized, would significantly decrease GHG emissions from fossil fuel-fired EGUs and the associated harms to human health and welfare. Further, the EPA has designed these proposed 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 proposed requirements, a less stringent set of requirements, and a more stringent set of requirements to inform EPA and the public about these projected impacts. With respect to the new source standard, the more stringent scenario differs from the proposal in that it assumes imposition of the second phase of the NSPS in run year 2030, while the proposal and less stringent scenarios assume imposition of the second phase of the NSPS in run year 2035. With regards to the existing source standard, the proposal and more stringent scenarios assume all long-term existing coal-fired steam generating units are subject to 90 percent CCS requirements in 2030, while the less stringent scenario assumes that long-term existing coal-fired steam generating units greater than 700 MW, and plants greater than 2,000 MW are subject to 90 percent CCS requirements, while those units less than 700 MW (and plants less than 2,000 MW) are subject to 40 percent natural gas co-firing requirements. 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 2042, 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, and 2040.

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 proposed 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 proposed 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."[14] EPA has listed more than 60 stationary source categories under this provision.[15] 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.[16] 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

[14] CAA §111(b)(1)(A).
[15] See 40 CFR 60 subparts Cb – OOOO.
[16] CAA §111(b)(1)(B), 111(a)(1).

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 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."[17] 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.[18] 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 proposed rules for more detailed statutory background and regulatory history for CAA Section 111.

1.2.1.1 Regulated Pollutant

In 2009, EPA concluded that GHG emissions endanger our nation's public health and welfare.[19] Since that time, the evidence of the harms posed by GHG emissions has only grown, and Americans experience the effects of climate change every day.

[17] CAA section 111(d)(2)(A).
[18] CAA section 111(d)(2)(A).
[19] 74 FR 66496 (December 15, 2009).

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, X, and XI of the preamble.

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 proposed 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 proposed regulation 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 and existing fossil fuel-fired stationary combustion turbine EGUs 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 IX of the preamble explains that EPA is proposing to repeal 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.[20]

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.[21] 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 and the District of Columbia. 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

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[20] In comparison, the current proposal is projected to reduce 89 million metric tons of CO_2 in 2030 (see Table 3-5).
[21] See *Heat Rate Improvement Method Costs and Limitations Memo*, which is available in the docket for this action.

GHG reductions consistent with the RIA. Because of these factors, the ACE Rule RIA results should be treated as speculative at best. Note that even if we assumed the same degree of 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 projected retirements in the coming years.[22]

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 proposed 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 proposed 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 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 proposed 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 post-IRA IPM 2022 reference case") 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

[22] 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.

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 2042 from the perspective of 2024, using both a three percent and seven percent discount rate. 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, and 2040. 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 2042. The year 2028 is the first year of detailed power sector modeling for this RIA and approximates when the regulatory impacts of the proposed 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 2042, as this is the last year that may be represented with the analysis conducted for the specific year of 2040.

1.3.3 Best System of Emission Reduction (BSER)

These actions include proposed BSER determinations and accompanying standards of performance for GHG emissions from new and reconstructed fossil fuel-fired stationary combustion turbines, proposed repeal of the ACE Rule, proposed BSER determinations and emission guidelines for existing fossil fuel-fired steam generating units, proposed BSER determinations and emission guidelines for large, frequently used existing fossil fuel-fired stationary combustion turbines, and solicitation for comment on potential BSER options and emission guidelines for existing fossil fuel-fired stationary combustion turbines not otherwise covered by the proposal.

For new and reconstructed fossil fuel-fired combustion turbines, the EPA is proposing to create three subcategories based on the function the combustion turbine serves: a low load (“peaking units”) subcategory that consists of combustion turbines with a capacity factor of less than 20 percent; an intermediate load subcategory for combustion turbines with a capacity factor that ranges between 20 percent and a source-specific upper bound that is based on the design efficiency of the combustion turbine; and a base load subcategory for combustion turbines that operate above the upper-bound threshold for intermediate load turbines. This subcategorization approach is similar to the current NSPS for these sources, which includes separate subcategories for base load and non-base load units; however, the EPA is now proposing to subdivide the non-base load subcategory into a low load subcategory and a separate intermediate load subcategory. This revised approach to subcategories is consistent with the fact that utilities and power plant operators are building new combustion turbines with plans to operate them at varying levels of capacity, in coordination with existing and expected energy sources. These patterns of operation are important for the type of controls that the EPA is proposing as the BSER for these turbines, in terms of the feasibility of, emissions reductions that would be achieved by, and cost-reasonableness of, those controls.

For the low load subcategory, the EPA is proposing that the BSER is the use of lower emitting fuels (*e.g.*, natural gas and distillate oil) with standards of performance ranging from 120 lb CO_2/MMBtu to 160 lb CO_2/MMBtu, depending on the type of fuel combusted.[23] For the intermediate load and base load subcategories, the EPA is proposing an approach in which the BSER has multiple components: (1) highly efficient generation; and (2) depending on the subcategory, use of CCS or co-firing low-GHG hydrogen.

These components of the BSER for the intermediate and base load subcategories form the basis of a standard of performance that applies in multiple phases. That is, affected facilities—which are facilities that commence construction or reconstruction after the date of publication in the *Federal Register* of this proposed rulemaking—must meet the first phase of the standard of performance, which is based exclusively on application of the first component of the BSER (highly efficient generation), by the date the rule is promulgated. Affected sources in the intermediate load and base load subcategories must also meet the second and in some cases third and more stringent phases of the standard of performance, which are based on the continued

[23] In the 2015 NSPS, the EPA referred to clean fuels as fuels with a consistent chemical composition (i.e., uniform fuels) that result in a consistent emission rate of 69 kilograms per gigajoule (kg/GJ) (160 lb CO2/MMBtu). Fuels in this category include natural gas and distillate oil. In this rulemaking, the EPA refers to these fuels as both lower emitting fuels or uniform fuels.

application of the first component of the BSER and the application of the second and in some cases third component of the BSER. For base load units, the EPA is proposing two pathways as potential BSER—(1) the use of CCS to achieve a 90 percent capture of GHG emissions by 2035 and (2) the co-firing of 30 percent (by volume) low-GHG hydrogen by 2032 and, ramping up to 96 percent by volume low-GHG hydrogen by 2038. These two BSER pathways both offer significant opportunities to reduce GHG emissions but, may be available on slightly different timescales.

More specifically, with respect to the first phase of the standards of performance, the EPA is proposing that the BSER for both the intermediate load and base load subcategories includes highly efficient generating technology (*i.e.*, the most efficient available turbines). For the intermediate load subcategory, the EPA is proposing that the BSER includes highly efficient simple cycle combustion turbine technology with an associated first phase standard of 1,150 lb CO_2/MWh-gross. For the base load subcategory, the EPA is proposing that the BSER includes highly efficient combined cycle technology with an associated first phase standard of 770 lb CO_2/MWh-gross for larger combustion turbine EGUs with a base load rating of 2,000 MMBtu/h or more. For smaller base load combustion turbines (with a base load rating of less than 2,000 MMBtu/h), the proposed associated standard would range from 770 to 900 lb CO_2/MWh-gross depending on the specific base load rating of the combustion turbine. These standards would apply immediately upon the effective date of the final rule.

With respect to the second phase of the standards of performance, for the intermediate load subcategory, the EPA is proposing that the BSER includes co-firing 30 percent by volume low-GHG hydrogen (unless otherwise noted, all co-firing hydrogen percentages are on a volume basis) with an associated standard of 1,000 lb CO_2/MWh-gross, compliance with which would be required starting in 2032. For the base load subcategory, to elicit comment on both pathways, the EPA is proposing to subcategorize further into base load units that are adopting the CCS pathway and base load units that are adopting the low-GHG hydrogen co-firing pathway. For the subcategory of base load units that are adopting the CCS pathway, the EPA is proposing that the BSER includes the use of CCS with 90 percent capture of CO_2 with an associated standard of 90 lb CO_2/MWh-gross, compliance with which would be required starting in 2035. For the subcategory of base load units that are adopting the low-GHG hydrogen co-firing pathway, the EPA is proposing that the BSER includes co-firing 30 percent (by volume) low-GHG hydrogen with an associated standard of 680 lb CO_2/MWh-gross, compliance with which would be required starting in 2032, and co-firing 96 percent (by volume) low-GHG hydrogen by 2038, which corresponds to a standard of performance of 90 lb CO_2/MWh-gross. In both cases, the second (and sometimes third) phase standard of performance would be applicable to all combustion turbines that were subject to the first phase standards of performance.

With respect to existing coal-fired steam generating units, the EPA is proposing to repeal and replace the existing ACE Rule emission guidelines. The EPA recognizes that, since it promulgated the ACE Rule, the costs of CCS have decreased due to technology advancements as well as new policies including the expansion of the Internal Revenue Code section 45Q tax credit for CCS in the Inflation Reduction Act (IRA); and the costs of natural gas co-firing have decreased as well, due in large part to a decrease in the difference between coal and natural gas prices. As a result, the EPA considered both CCS and natural gas co-firing as candidates for BSER for existing coal-fired steam EGUs.

Based on the latest information available to the Agency on cost, emission reductions, and other statutory criteria, the EPA is proposing that the BSER for existing coal-fired steam EGUs that expect to operate in the long-term is CCS with 90 percent capture of CO_2. The EPA has determined that CCS satisfies the BSER criteria for these sources because it is adequately demonstrated, achieves significant reductions in GHG emissions, and is highly cost-effective.

In response to industry stakeholder input descried in sections I.B.2 and X.C.3 of the preamble, and recognizing that the cost effectiveness of controls depends on the unit's expected operating time horizon, which dictates the amortization period for the capital costs of the controls, the EPA believes it is appropriate to establish subcategories of existing steam EGUs that are based on the operating horizon of the units. The EPA is proposing that for units that expect to operate in the long-term (*i.e.*, those that plan to operate past December 31, 2039), the BSER is the use of CCS with 90 percent capture of CO_2 with an associated degree of emission limitation of an 88.4 percent reduction in emission rate (lb CO_2/MWh-gross basis). As explained in detail in this proposal, CCS with 90 percent capture of CO_2 is adequately demonstrated, cost reasonable, and achieves substantial emissions reductions from these units.

The EPA is proposing to define coal-fired steam generating units with medium-term operating horizons as those that (1) operate after December 31, 2031, (2) have elected to commit to permanently cease operations before January 1, 2040, (3) elect to make that commitment federally enforceable and continuing by including it in the state plan, and (4) do not meet the definition of near-term operating horizon units. For these medium-term operating horizon units, the EPA is proposing that the BSER is co-firing 40 percent natural gas on a heat input basis with an associated degree of emission limitation of a 16 percent reduction in emission rate (lb CO_2/MWh-gross basis). While this subcategory is based on a 10-year operating horizon (*i.e.*, January 1, 2040), the EPA is specifically soliciting comment on the potential for a different operating horizon between 8 and 10 years to define the threshold date between the definition of medium-term and long-term coal-fired steam generating units (*i.e.*, January 1, 2038 to January 1, 2040), given that the costs for CCS may be reasonable for units with amortization periods as short as 8 years. For units with operating horizons that are imminent-term, i.e., those that (1) have elected to commit to permanently cease operations before January 1, 2032, and (2) elect to make that commitment federally enforceable and continuing by including it in the state plan, the EPA is proposing that the BSER is routine methods of operation and maintenance with an associated degree of emission limitation of no increase in emission rate (lb CO_2/MWh-gross basis). The EPA is proposing the same BSER determination for units in the near-term operating horizon subcategory, i.e., units that (1) have elected to commit to permanently cease operations by December 31, 2034, as well as to adopt an annual capacity factor limit of 20 percent, and (2) elect to make both of these conditions federally enforceable by including them in the state plan. The EPA is also soliciting comment on a potential BSER based on low levels of natural gas co-firing for units in these last two subcategories.

The EPA is also proposing emission guidelines for existing natural gas-fired and oil-fired steam generating units. Recognizing that virtually all of these units have limited operation, the EPA is, in general, proposing that the BSER is routine methods of operation and maintenance with an associated degree of emission limitation of no increase in emission rate (lb CO_2/MWh-gross).

The EPA is also proposing emission guidelines for large (*i.e.*, greater than 300 MW), frequently operated (*i.e.*, with a capacity factor of greater than 50 percent), existing fossil fuel-fired stationary combustion turbines. Because these existing combustion turbines are similar to new stationary combustion turbines, the EPA is proposing a BSER that is similar to the BSER for new base load combustion turbines. The EPA is not proposing a first phase efficiency-based standard of performance; but the EPA is proposing that BSER for these units is based on either the use of CCS by 2035 or co-firing of 30 percent (by volume) low-GHG hydrogen by 2032 and co-firing 96 percent low-GHG hydrogen by 2038.

For the emission guidelines for existing fossil fuel-fired steam generating units and large, frequently operated fossil fuel-fired combustion turbines, the EPA is also proposing state plan requirements, including submittal timelines for state plans and methodologies for determining presumptively approvable standards of performance consistent with BSER. This proposal also addresses how states can implement the remaining useful life and other factors (RULOF) provision of CAA section 111(d) and how states can conduct meaningful engagement with impacted stakeholders. Finally, the EPA is proposing to allow states to include trading or averaging in state plans so long as they demonstrate equivalent emissions reductions, and this proposal discusses considerations related to the appropriateness of including such compliance flexibilities.

For additional information on BSER in these actions, please see the preamble for these actions. 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 benefits, costs and certain impacts of compliance with three illustrative scenarios: the proposal, a less stringent scenario, and a more stringent scenario. The modeling of the illustrative proposal scenario that is discussed in Sections 3 through 7 of this RIA includes all aspects of the proposed 111(d) requirements for existing fossil fuel-fired steam generating units and most aspects of the proposed 111(b) requirements for new and reconstructed stationary combustion turbines. However, it does not reflect the proposed 111(d) requirements for existing stationary combustion turbines or one additional component of the 111(b) requirements (for new base load combustion turbines in the hydrogen co-firing subcategory, the third phase standard based on co-firing 96 percent low-GHG hydrogen by 2038). For these additional measures, EPA performed a spreadsheet-based analysis of regulatory impacts that is discussed in Section 8 of this RIA.

With respect to the new source standard, the more stringent scenario differs from the proposal in that it assumes imposition of the second phase of the NSPS in run year 2030, while the proposal and less stringent scenarios assume imposition of the second phase of the NSPS in run year 2035. With regards to the existing source standard, the proposal and more stringent scenarios assume all long-term existing coal-fired steam generating units are subject to 90 percent CCS requirements in 2030, while the less stringent scenario assumes that long-term existing coal-fired steam generating units greater than 700 MW, and plants greater than 2,000 MW are subject to 90 percent CCS requirements, while those units less than 700 MW (and plants less than 2,000 MW) are subject to 40 percent natural gas co-firing requirements.

The GHG mitigation measures in this RIA are illustrative since States are afforded flexibility to implement the proposed 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: Economic Impact Analysis**. This section includes a discussion of potential small entity, economic, 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.
- **Section 8: Impacts of Proposed 111(d) Standards on Existing Natural Gas-fired EGUs and Third Phase of Proposed 111(b) Standards on New Natural Gas-fired EGUs:** This section summarizes the cost and emissions impact analysis of the proposed standards for existing natural gas-fired EGUs and the third phase of the proposed standards for new natural gas-fired EGUs.
- **Appendix A: 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 policy scenario and presents resulting surfaces that represent air quality changes associated with the illustrative scenarios.
- **Appendix B: Economy-wide Social Costs and Economic Impacts.** This section presents estimates of economy-wide social costs and economic impacts of these proposed rules from a computable general equilibrium (CGE) model of the United States economy, SAGE, as a complement to other analyses in this RIA.
- **Appendix C: Assessment of Potential Costs and Emissions Impacts of Proposed 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

U.S. EPA. (2014). *Guidelines for Preparing Economic Analyses*. (EPA 240-R-10-001). Washington DC: U.S. Environmental Protection Agency, Office of Policy, National Center for Environmental Economics. https://www.epa.gov/environmental-economics/guidelines-preparing-economic-analyses

U.S. EPA. (2019). *Regulatory Impact Analysis for the Repeal of the Clean Power Plan, and the Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units*. (EPA-452/R-19-003). Research Triangle Park, NC: U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Health and Environmental Impact Division. https://www.epa.gov/sites/production/files/2019-06/documents/utilities_ria_final_cpp_repeal_and_ace_2019-06.pdf

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.[24] 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. This section presents data on the evolution of the power sector over the past two decades from 2010 through 2021, as well as a focus on the period 2015 through 2021. Projections of future power sector behavior and the impact of the proposed 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 Capacity* refers to the maximum amount of production an EGU is capable of producing in a

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

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 2021 and 2015 to 2021.

In 2021 the power sector comprised a total capacity[25] of 1,179 GW, an increase of 140 GW (or 13 percent) from the capacity in 2010 (1,039 GW). The largest change over this period was the decline of 107 GW of coal capacity, reflecting the retirement/rerating of over a third of the coal fleet. This reduction in coal capacity was offset by increases in natural gas, solar, and wind capacities of 85 GW, 61 GW, and 94 GW respectively. Substantial amounts of distributed solar (33 GW) were also added.

These trends persist over the shorter 2015-21 period as well; total capacity in 2021 (1,179 GW) increased by 105 GW (or 10 percent). The largest change in capacity was driven by a reduction of 70 GW of coal capacity. This was offset by a net increase of 52 GW of natural gas capacity, an increase of 60 GW of wind, and an increase of 48 GW of solar. Additionally, 23 GW of distributed solar were also added over 2015-21.

[25] 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, 2010-21 and 2015-21

	2010		2021		Change Between '10 and '21	
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%	210	18%	-34%	-107
Natural Gas	407	39%	492	42%	21%	85
Nuclear	101	10%	96	8%	-6%	-6
Hydro	101	10%	103	9%	2%	2
Petroleum	56	5%	28	2%	-49%	-27
Wind	39	4%	133	11%	239%	94
Solar	1	0%	62	5%	7004%	61
Distributed Solar	0	0%	33	3%		33
Other Renewable	14	1%	15	1%	9%	1
Misc	4	0%	8	1%	129%	5
Total	1,039	100%	1,179	100%	13%	140

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

Source: EIA. Electric Power Annual 2021, Table 4.2.A

The average age of coal-fired power plants that retired between 2015 and 2021 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.[26] As shown in Figure 2-1 below, 65 percent of the coal fleet in 2021 had an average age of over 40 years.

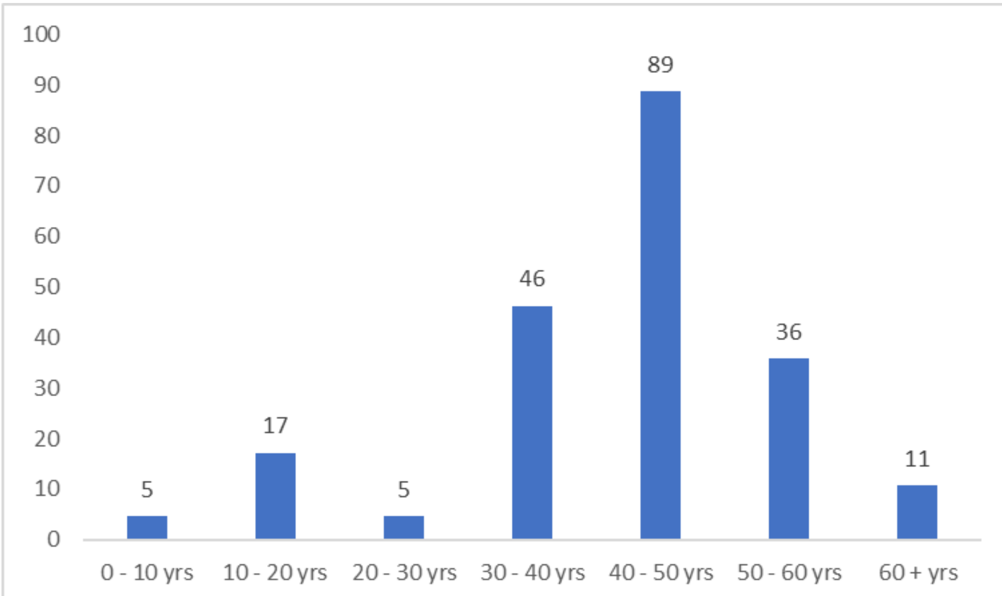

Figure 2-1 National Coal-fired Capacity (GW) by Age of EGU, 2021
Source: NEEDS v6

In 2021, electric generating sources produced a net 4,157 TWh to meet national electricity demand, which was around 1 percent higher than 2010. As presented in Table 2-2, 59 percent of electricity in 2021 was produced through the combustion of fossil fuels, primarily coal and natural gas, with natural gas accounting for the largest single share. The total generation share from fossil fuels in 2021 (60 percent) was 11 percent less than the share in 2010 (69 percent). Moreover, the share of fossil generation supplied by coal fell from 65 percent in 2010 to 36 percent by 2021, while the share of fossil generation supplied by natural gas rose from 35 percent to 64 percent over the same period. In absolute terms, coal generation declined by 51 percent, while natural gas generation increased by 60 percent. This reflects both the increase in natural gas capacity during that period as well as an increase in the utilization of new and existing gas EGUs during that period. The combination of wind and solar generation also grew from 2 percent of the mix in 2010 to 13 percent in 2021.

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

Table 2-2 Net Generation by Energy Source, 2010 - 21 and 2015 - 21 (Trillion kWh = TWh)

	2010		2021		Change Between '10 and '21	
Energy Source	**Net Generation (TWh)**	**Fuel Source Share**	**Net Generation (TWh)**	**Fuel Source Share**	**% Increase**	**Generation Change (TWh)**
Coal	1,847	45%	898	22%	-51%	-949
Natural Gas	988	24%	1,579	38%	60%	592
Nuclear	807	20%	778	19%	-4%	-29
Hydro	255	6%	246	6%	-3%	-8
Petroleum	37	1%	19	0%	-48%	-18
Wind	95	2%	378	9%	300%	284
Solar	1	0%	115	3%	9410%	114
Distributed Solar	0	0%	49	1%		49
Other Renewable	71	2%	70	2%	-2%	-1
Misc	24	1%	24	1%	-3%	-1
Total	4,125	100%	4,157	100%	1%	32

Table 2-3 Net Generation in 2015 and 2021 (Trillion kWh = TWh)

	2015		2021		Change Between '15 and '21	
Energy Source	**Net Generation (TWh)**	**Fuel Source Share**	**Net Generation (TWh)**	**Fuel Source Share**	**% Increase**	**Generation Change (TWh)**
Coal	1,352	33%	898	22%	-34%	-455
Natural Gas	1,335	33%	1,579	38%	18%	246
Nuclear	797	19%	778	19%	-2%	-19
Hydro	249	6%	252	6%	1%	2
Petroleum	28	1%	19	0%	-32%	-9
Wind	191	5%	378	9%	98%	187
Solar	25	1%	115	3%	363%	90
Distributed Solar	14	0%	49	1%	248%	35
Other Renewable	80	2%	70	2%	-12%	-9
Misc	27	1%	24	1%	-13%	-4
Total	4,092	100%	4,157	100%	2%	66

Source: EIA. Electric Power Annual 2021, 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 18 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 49 percent over the 2010 to 2021 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 55 percent.

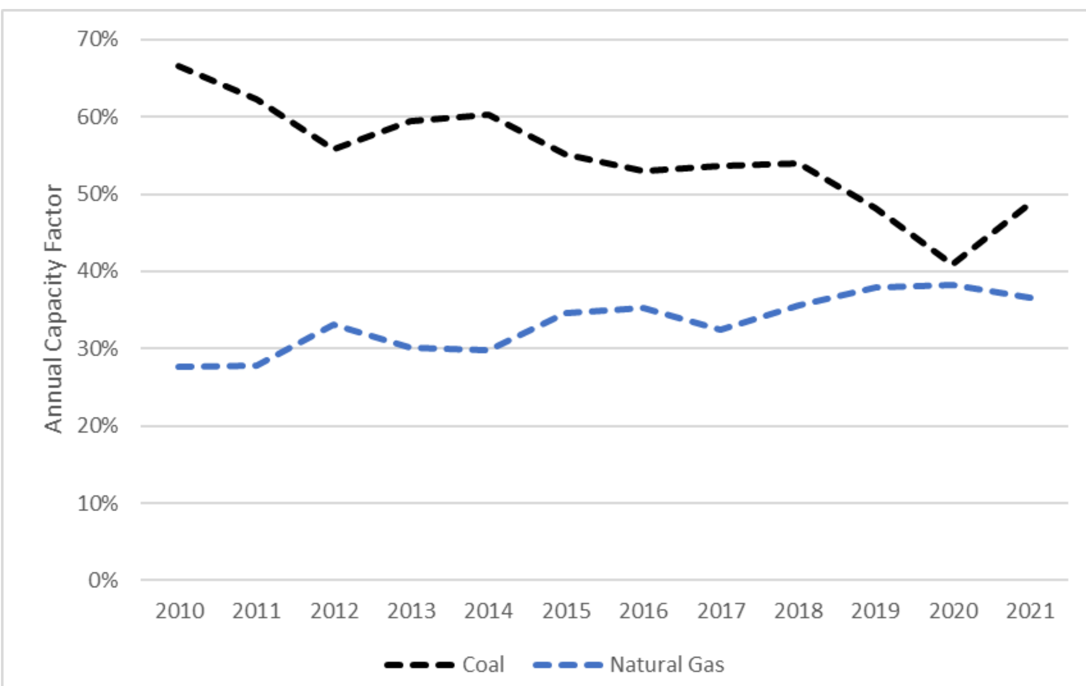

Figure 2-2 Average Annual Capacity Factor by Energy Source
Source: EIA. Electric Power Annual 2021, Table 4.8.A

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 67 percent of the coal EGU fleet capacity is over 500 MW per unit, 75 percent of the gas fleet is between 50 and 500 MW per unit.

Table 2-4 Coal and Natural Gas Generating Units, by Size, Age, Capacity, and Average Heat Rate in 2020

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

Source: National Electric Energy Data System (NEEDS) v.6

Note: The average heat rate reported is the mean of the heat rate of the units in each size category (as opposed to a generation-weighted or capacity-weighted average heat rate.) A lower heat rate indicates a higher level of fuel efficiency.

In terms of the age of the generating units, almost 50 percent of the total coal generating capacity has been in service for more than 40 years, while nearly 50 percent of the natural gas capacity has been in service less than 15 years. Figure 2-3 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.

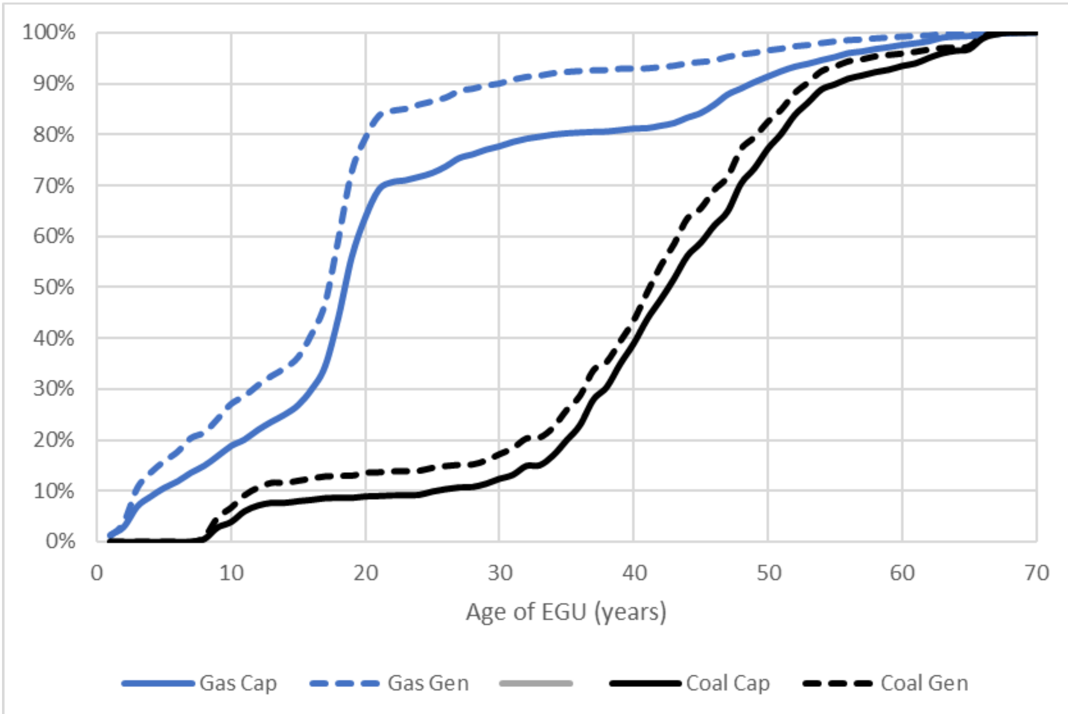

Figure 2-3 Cumulative Distribution in 2020 of Coal and Natural Gas Electricity Capacity and Generation, by Age

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

The locations of existing fossil units in EPA's National Electric Energy Data System (NEEDS) v.6 are shown in Figure 2-4.

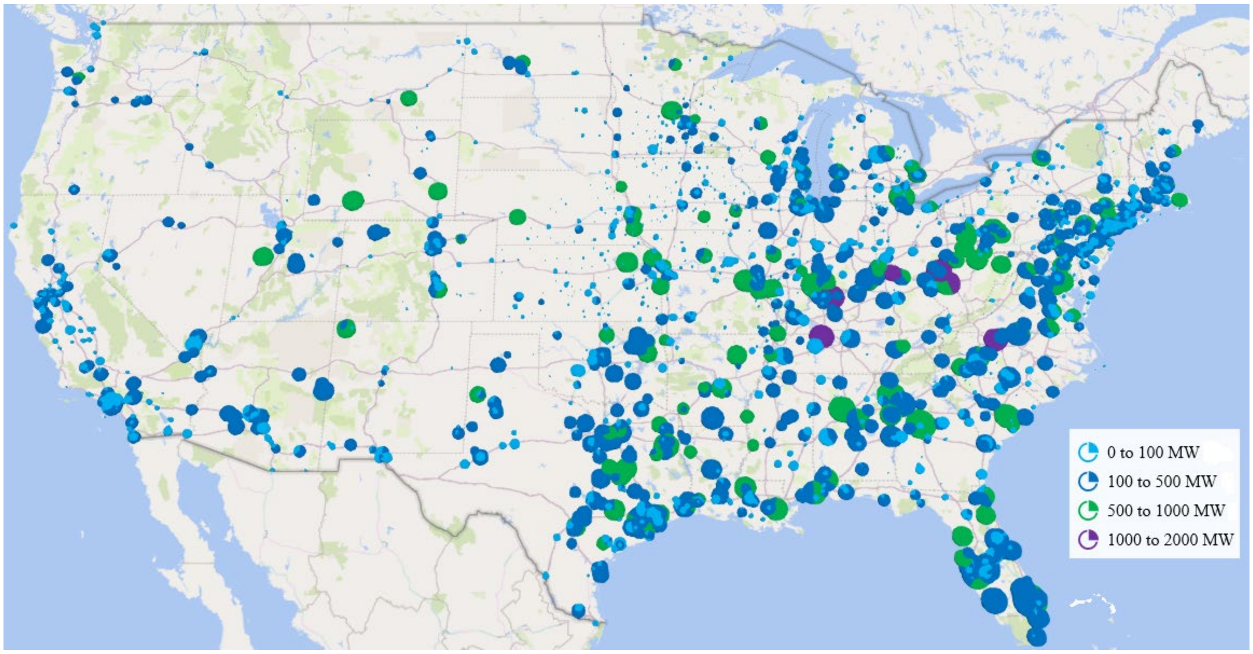

Figure 2-4 Fossil Fuel-Fired Electricity Generating Facilities, by Size
Source: National Electric Energy Data System (NEEDS) v.6
Note: This map displays fossil capacity at facilities in the NEEDS v.6 IPM frame. NEEDS v.6 reflects generating capacity expected to be on-line at the end of 2023. This includes 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.[27] 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[28], DOE's Land-Based Wind Market Report[29], LBNL's

[27] Lazard, Levelized Cost of Energy Analysis-Version 15.0, 2021. https://www.lazard.com/media/451905/lazards-levelized-cost-of-energy-version-150-vf.pdf
[28] Available at: https://atb.nrel.gov/
[29] Available at: https://www.energy.gov/eere/wind/articles/land-based-wind-market-report-2022-edition

Utility Scale solar report[30], EIA's Annual Energy Outlook[31], and DOE's 2022 Grid Energy Storage Technology Cost and Performance Assessment.[32]

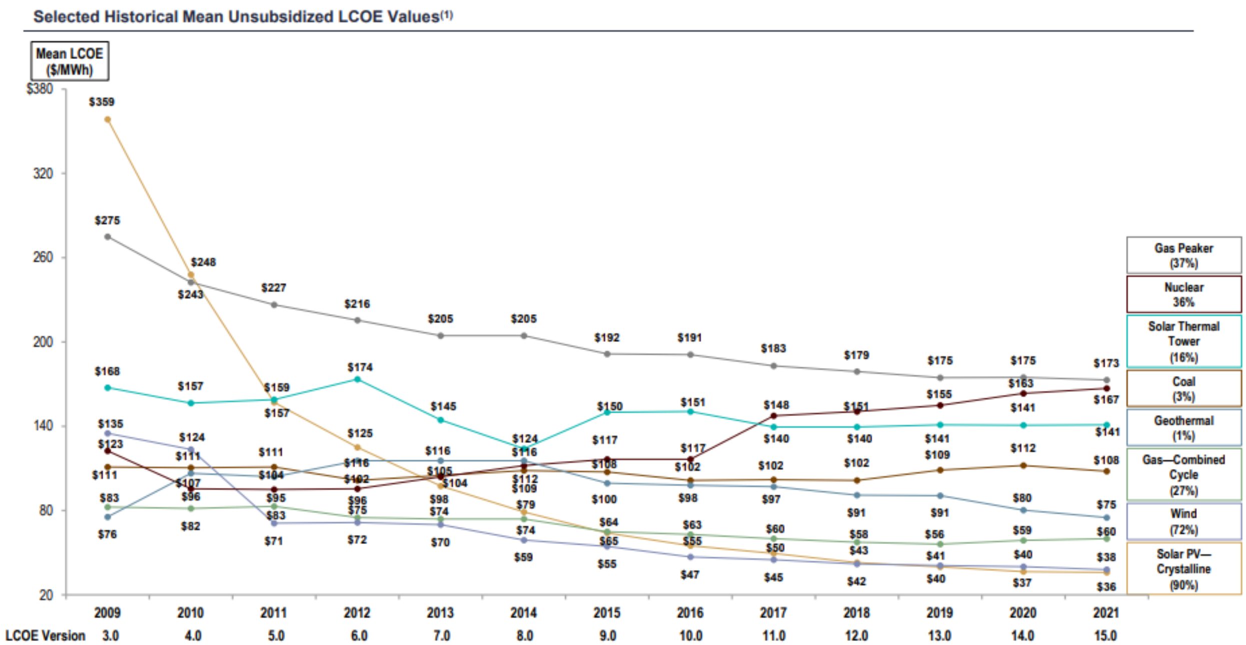

Figure 2-5 Selected Historical Mean LCOE Values
Source: Lazard, Levelized Cost of Energy Analysis-Version 15.0, October 2021

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, most 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 with the final 2030 goals of the rule—in terms of gross emissions reductions—before the 2022

[30] Available at: https://emp.lbl.gov/utility-scale-solar/
[31] Available at: https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf
[32] Available at: https://www.energy.gov/eere/analysis/2022-grid-energy-storage-technology-cost-and-performance-assessment

start date included in that program."[33] 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.

There are many recent examples of electric utilities that have publicly announced near- and long-term emission reduction commitments. Here are but a few examples of emission reduction targets of 80 percent or more (relative to 2005 levels) that have recently been announced by major utilities that together serve roughly 40 million electric customers:

- **Xcel Energy** (with power plants that operate in MN, CO, MI, MN, NM, ND, SD, TX, and WI): 85 percent reduction in CO_2 emissions by 2030 and carbon-free by 2050. This includes a commitment to close or repower all remaining coal units by 2040.[34]
- **DTE Energy** (MI): 50 percent reduction in CO_2 by 2028, 80 percent by 2040, and carbon-free by 2050.[35]
- **Ameren Energy** (MO): 50 percent by 2030, 85 percent by 2040, and carbon-free by 2050.[36]
- **Consumers Energy (MI)**: Carbon-free by 2040. This includes company retiring all coal fire units by 2025.[37]
- **Duke Energy**: 50 percent reduction by 2030, carbon-free by 2050.[38]
- **Allete Inc**: 50 percent reduction by 2030, 80 percent reduction by 2035, carbon-free by 2050.[39]
- **First Energy (FE)**: Carbon-free by 2050.[40]
- **American Electric Power (AEP)**: 80 percent reduction by 2030 and carbon-free

[33] EEI Comments on ACE, at 4 (Oct. 31, 2018)
[34] Xcel Energy, Press Release, *available at:* https://investors.xcelenergy.com/news-market-information/press-releases/press-release/2021/Xcel-Energy-Announces-2030-Clean-Energy-Plan-to-Reduce-Carbon-Emissions-85/default.aspx
[35] DTE Energy, Powering towards a net zero carbon future, available at: https://dtecleanenergy.com/pathway-to-net-zero/
[36] Ameren Missouri, 2021 Climate Report, *available at:* https://www.ameren.com/-/media/corporate-site/files/environment/reports/climate-report-tcfd.pdf?La=en&hash=B6CEB8301F0356B4E37B35176826FEEAFFEB5A1E%20
[37] Consumers Energy, News Release, *available at* https://www.consumersenergy.com/news-releases/news-release-details/2021/06/23/consumers-energy-announces-plan-to-end-coal-use-by-2025-lead-michigans-clean-energy-transformation
[38] Duke Energy, News Release, available at https://news.duke-energy.com/releases/duke-energy-expands-clean-energy-action-plan#:~:text=And%20it%20is%20on%20pace,approximately%207%2C500%20megawatts%20since%202010.
[39] Allete Energy, New Release, *available at*: https://investor.allete.com/news-releases/news-release-details/minnesota-power-announces-vision-100-percent-carbon-free-energy
[40] First Energy, available at https://www.firstenergycorp.com/environmental.html

by 2050 (from year 2000 levels).[41]

- **Alliant Energy**: 50 percent reduction by 2030 and carbon-free by 2050 and retiring final coal fire plant by 2024.[42]
- **Tennessee Valley Authority**: 70 percent reduction by 2030, 80 percent reduction by 2035, carbon-free by 2050.[43]

While EPA does not account for statements from utilities regarding their future plans that are not technically legally enforceable in the economic modeling, the number and scale of these announcements is significant on a systemic level. These statements are also part of long- term planning processes that cannot be easily revoked, since there is considerable stakeholder involvement, including by regulators, in the planning process. The direction in which these companies 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 there is a high likelihood that most 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,[44] 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

[41] AEP, available at http://www.aepsustainability.com/environment/carbon/

[42] Alliant Energy, available at https://www.alliantenergy.com/cleanenergy/ourenergyvision/responsibilityreport/cleanenergyvisiongoals?utm_source=WS&utm_campaign=Legacy&utm_medium=AboutAlliantEnergy/ResponsibilityReport/CleanEnergyVisionGoals

[43] TVA, *available at*: https://www.tva.com/newsroom/press-releases/tva-charts-path-to-clean-energy-future

[44] These three network interconnections are the Western Interconnection, comprising the western parts of both the U.S. and Canada (approximately the area to the west of the Rocky Mountains), the Eastern Interconnection, comprising the eastern parts of both the U.S. and Canada (except those part of eastern Canada that are in the Quebec Interconnection), and the Texas Interconnection (which encompasses the portion of the Texas electricity system commonly known as the Electric Reliability Council of Texas (ERCOT)). See map of all NERC interconnections at https://www.nerc.com/AboutNERC/keyplayers/PublishingImages/NERC%20Interconnections.pdf.

regional operator;[45] in others, individual utilities[46] coordinate the operations of their generation, transmission, and distribution systems to balance the system across their respective service territories.

2.2.3 Distribution

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

Over the last few decades, several jurisdictions in the United States began restructuring the power industry to separate transmission and distribution from generation, ownership, and operation. Historically, vertically integrated utilities established much of the existing transmission infrastructure. However, as parts of the country have restructured the industry, transmission infrastructure has also been developed by transmission utilities, electric cooperatives, and merchant transmission companies, among others. Distribution, also historically developed by vertically integrated utilities, is now often managed by a number of utilities that purchase and sell electricity, but do not generate it. 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.

[45] For example, PJM Interconnection, LLC.
[46] For example, Los Angeles Department of Water and Power, Florida Power and Light.

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). [47] Some of these uses are highly variable, such as heating and air conditioning in residential and commercial buildings, while others are relatively constant, such as industrial processes that operate 24 hours a day. The distribution between the end use categories changed very little between 2010 and 2020.

Table 2-5 Total U.S. Electric Power Industry Retail Sales, 2010-21 and 2014-21 (billion kWh)

		2010		2021	
		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%	1,470	37%
	Commercial	1,330	34%	1,328	34%
	Industrial	971	25%	1,001	25%
	Transportation	8	0%	6	0%
Total		3,755	97%	3,806	96%
Direct Use			132	3%	139
Total End Use			**3,887**	**100%**	**3,945**
		2015		**2021**	
		Sales/Direct Use (Billion kWh)	**Share of Total End Use**	**Sales/Direct Use (Billion kWh)**	**Share of Total End Use**
Sales	Residential	1,404	36%	1,470	37%
	Commercial	1,361	35%	1,328	34%
	Industrial	987	25%	1,001	25%
	Transportation	8	0%	6	0%
Total		3,759	96%	3,806	96%
Direct Use			141	4%	139
Total End Use			**3,900**	**100%**	**3,945**

Source: Table 2.2, EIA Electric Power Annual, 2020, Electric Power Monthly March 2022.
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.

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

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 2021, the national average retail electricity price (all sectors) was 11.10 cents/kWh, with a range from 8.1 cents (Idaho) to 30.31 cents (Hawaii).[48]

The real year prices for 2010 through 2021 are shown in Figure 2-6. Average national retail electricity prices decreased between 2010 and 2021 by 8 percent in real terms (2019 dollars), and 5 percent between 2015-21.[49] The amount of decrease differed for the three major end use categories (residential, commercial and industrial). National average industrial prices decreased the most (7 percent), and residential prices decreased the least (4 percent) between 2015-21.

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

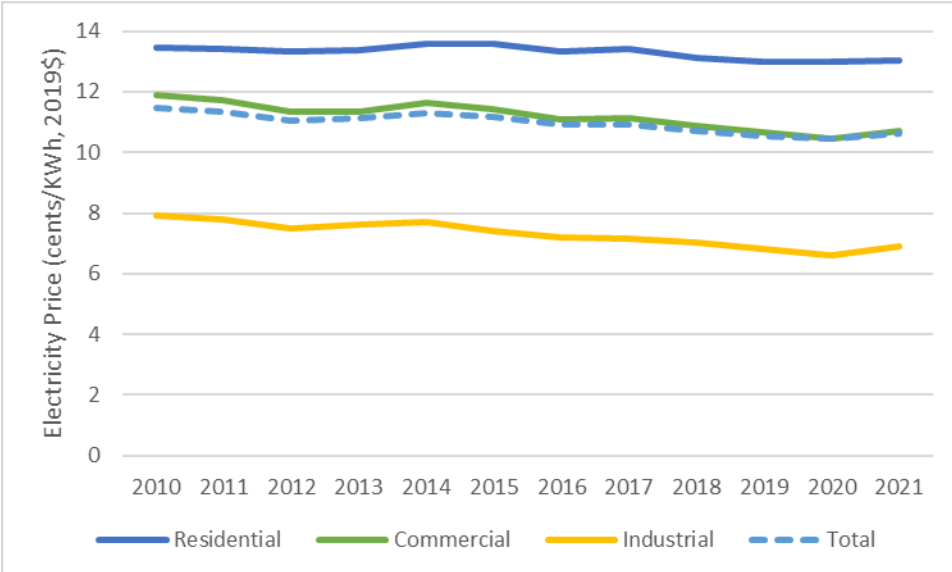

Figure 2-6 Real National Average Electricity Prices (including taxes) for Three Major End-Use Categories
Source: EIA. Electric Power Annual 2020 and 2021, Table 2.4.

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[50] for the three major fossil fuels used in electricity generation: coal, natural gas, and petroleum products. Relative to real prices in 2014, the national average real price (in 2019 dollars) of coal delivered to EGUs in 2020 had decreased by 26 percent, while the real price of natural gas decreased by 56 percent. The real price of delivered petroleum products also decreased by 55 percent, and petroleum products declined as an EGU fuel (in 2020 petroleum products generated 1 percent of electricity). The combined real delivered price of all fossil fuels (weighted by heat input) in 2020 decreased by 39 percent over 2014 prices. Figure 2-7 shows the relative changes in real price of all 3 fossil fuels between 2010 and 2021.

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

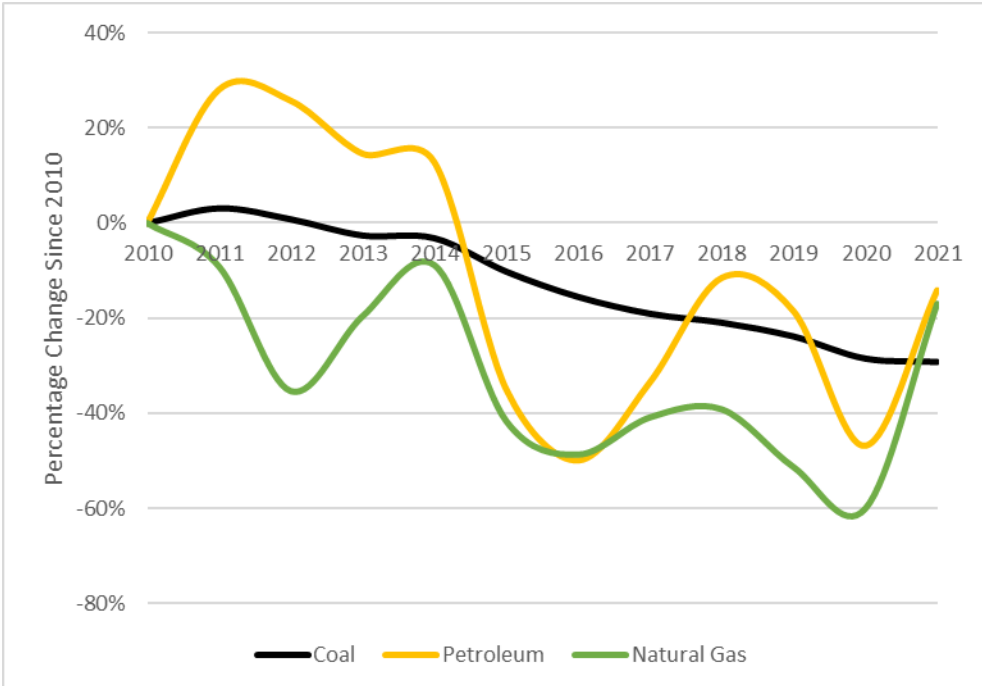

Figure 2-7 Relative Real Prices of Fossil Fuels for Electricity Generation; Change in National Average Real Price per MMBtu Delivered to EGU
Source: EIA. Electric Power Annual 2020 and 2021, Table 7.1.

2.3.3 Changes in Electricity Intensity of the U.S. Economy from 2010 to 2021

An important aspect of the changes in electricity generation (i.e., electricity demand) between 2010 and 2021 is that while total net generation increased by 1 percent over that period, the demand growth for generation was lower than both the population growth (7 percent) and real GDP growth (24 percent). Figure 2-8 shows the growth of electricity generation, population, and real GDP during this period.

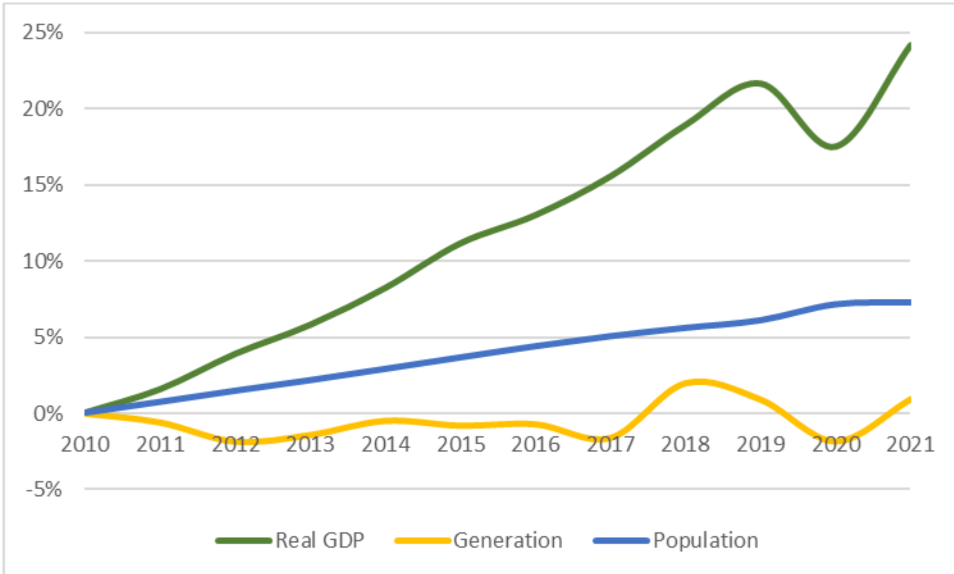

Figure 2-8 Relative Growth of Electricity Generation, Population and Real GDP Since 2010

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

Because demand for electricity generation grew more slowly than both the population and GDP, the relative electric intensity of the U.S. economy improved (i.e., less electricity used per person and per real dollar of output) during 2010 to 2021. On a per capita basis, real GDP per capita grew by 16 percent between 2010 and 2021. At the same time electricity generation per capita decreased by 6 percent. The combined effect of these two changes improved the overall electricity generation efficiency in the U.S. market economy. Electricity generation per dollar of real GDP decreased 19 percent. These relative changes are shown in Figure 2-9.

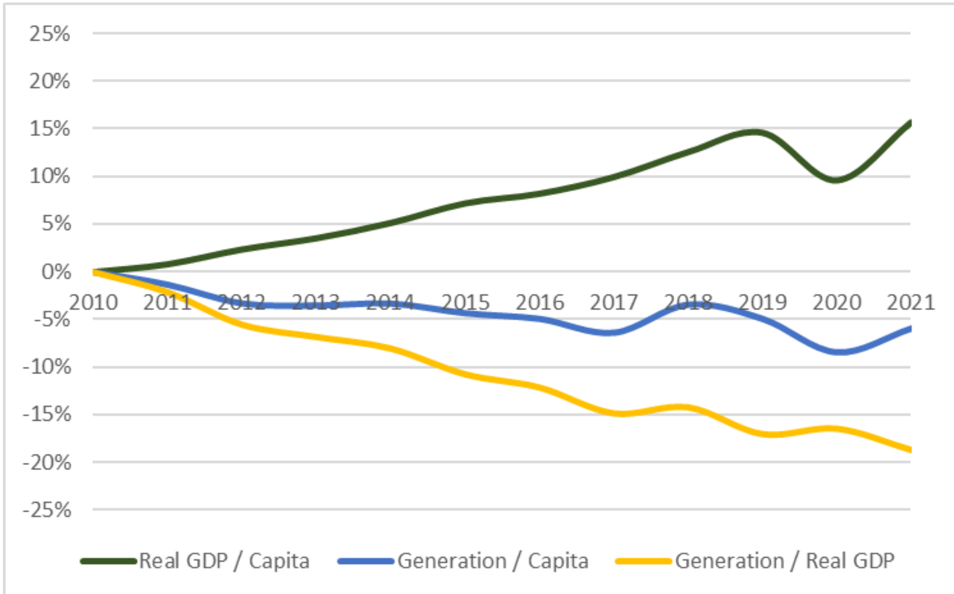

Figure 2-9 Relative Change of Real GDP, Population and Electricity Generation Intensity Since 2010

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

3 COMPLIANCE COSTS, EMISSIONS, AND ENERGY IMPACTS

3.1 Overview

This section reports the compliance costs, emissions, and energy analyses performed for the proposed NSPS and proposed Emission Guidelines. Section 3 pertains to the analysis of the proposed standards for new natural gas-fired EGUs and for existing coal-fired EGUs. Please see Section 8 for impact analysis of the proposed standards for existing natural gas-fired EGUs and the third phase of the proposed standards for new natural gas-fired EGUs. EPA used the Integrated Planning Model (IPM)[51] 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. The analysis presented in this section reflects the combined effects of the proposals on new and existing sources (with the exception of the proposed standards for existing natural gas-fired EGUs and the third phase of the proposed standards for new natural gas-fired EGUs, discussed in Section 8). The impacts of each action independently are presented in Appendix C.

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.[52]

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 EGUs and fossil-

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

[52] 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

fuel fired EGUs that commence construction or reconstruction after the publication of this proposed regulation. For details on the source categories and the mitigation measures considered please see sections VII, X and XI of the preamble.

This RIA evaluates the benefits, costs, and certain impacts of compliance with three illustrative scenarios: the proposal, a less stringent scenario, and a more stringent scenario. To the extent possible, EPA evaluated the 111(b) proposal for new natural-gas fired EGUs and 111(d) proposal for existing coal fired EGUs in combination to better analyze the interactive effects of the proposals. 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 GHG Mitigation Measures for Existing Sources by Source Category under the Illustrative Proposal and More Stringent Scenarios[a,b,c,d]

Affected EGUs	Subcategory Definition	GHG Mitigation Measure
Long-term existing coal-fired steam generating units	Coal-fired steam generating units without committed retirement prior to 2040	CCS with 90 percent capture of CO_2, starting in 2030
Medium-term existing coal-fired steam generating units	Coal-fired steam generating units with a committed retirement by 2040 that are less than 500 MW, and that are not a near-term/low utilization unit	Natural gas co-firing at 40 percent of the heat input to the unit, starting in 2030
Near-term existing coal-fired steam generating units	Coal-fired steam generating units with a committed retirement prior to 2035 that operate with annual capacity factors less than 20 percent in 2030	Routine methods of operation
Imminent-term existing coal-fired steam generating units	Coal-fired steam generating units with a federally enforceable retirement commitment prior to 2030	Routine methods of operation

[a] All years shown in this table reflect IPM run years.
[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 are no longer subject to coal-fired EGU mitigation measures outlined above.
[d] The modeling did not include GHG mitigation measure requirements on existing natural gas generation. These requirements are analyzed separately in Section 8.

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

Affected EGUs	Subcategory Definition	GHG Mitigation Measure
Long-term existing coal-fired steam generating units > 700 MW	Coal-fired steam generating units > 700 MW, or coal-fired steam generating plants > 2 GW, without committed retirement prior to 2040	CCS with 90 percent capture of CO_2, starting in 2030
Long-term existing coal-fired steam generating units < 700 MW	Coal-fired steam generating units < 700 MW without committed retirement prior to 2040	Natural gas co-firing at 40 percent of the heat input to the unit, starting in 2030
Near-term existing coal-fired steam generating units	Coal-fired steam generating units with a committed retirement prior to 2035 that operate with annual capacity factors less than 20 percent in 2030	Routine methods of operation
Imminent-term existing coal-fired steam generating units	Coal-fired steam generating units with a federally enforceable retirement commitment prior to 2030	Routine methods of operation

[a] All years shown in this table reflect IPM run years.
[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 are no longer subject to coal-fired EGU mitigation measures outlined above.
[d] The modeling did not include GHG mitigation measure requirements on existing natural gas generation. These requirements are analyzed separately in Section 8.

Table 3-3 Summary of GHG Mitigation Measures for New Sources by Source Category under the Illustrative Proposal, Less and More Stringent Scenarios[a,b,c,d]

Affected EGUs	Subcategory Definition	1st Component BSER	2nd Component BSER	Second Phase Applicability: Proposal and Less Stringent Scenario	Second Phase Applicability: More Stringent Scenario
Baseload Economic NGCC Additions	NGCC units that commence construction after 2023 and operate at an annual capacity factor of more than 50%	Efficient generation	30% by volume hydrogen co-firing or CCS	2035	2030
Intermediate Load Economic NGCC Additions	NGCC units that commence construction after 2023 and operate at an annual capacity factor of less than 50%	Efficient generation	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%	Efficient generation	48% by volume hydrogen co-firing[e]		
Peaking Economic NGCT Additions	NGCT units that commence construction after 2023 and operate at an annual capacity factor of less than 20%	Efficient generation	Efficient generation		

[a] All years shown in this table reflect IPM run years.
[b] Delivered hydrogen price is assumed to be $0.5/kg in years in which second phase of the NSPS is active, and $1/kg in all other years.
[c] NGCC unit additions that install CCS are no longer subject to the GHG mitigation measures outlined above.
[d] The modeling did not include certain elements of the new source performance standard. These requirements are analyzed separately in Section 8.
[e] Efficient combustion turbines co-firing 30% low-GHG hydrogen are assumed to achieve the BSER-associated intermediate load standard of 1,000 lb/MWh, as described in the preamble. However, the illustrative modeling scenarios assume a higher level of co-firing (48%) to achieve the intermediate load standard. This discrepancy, based on the use of an earlier assumption, is unlikely to significantly affect model projections.

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.[53] This

[53] 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

RIA analyzes the proposal, as well as a more and a less stringent scenario. The more stringent scenario differs from the proposal in that it assumes imposition of the second phase of the NSPS requirements on new sources in run year 2030, while the proposal and less stringent scenarios assume imposition of second phase of the NSPS requirements in run year 2035. The proposal and more stringent scenarios assume all long-term existing coal-fired steam generating units are subject to 90 percent CCS requirements in 2030[54], while the less stringent scenario assumes that long-term existing coal-fired steam generating units greater than 700 MW, and plants greater than 2,000 MW are subject to 90 percent CCS requirements, while those less than 700 MW are subject to 40 percent natural gas co-firing requirements.

The GHG mitigation measures in this RIA are illustrative since States are afforded flexibility to implement the proposed 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 illustrative proposal scenario.

EPA estimates that industry will incur MR&R costs due to the Proposed 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 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 2025 are approximately $13,000 in 2019 dollars, and then increase by approximately $61,000 in 2019 dollars each year thereafter

[54] 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.

to reflect costs associated with additional respondents.[55] We estimate that states will not incur MR&R costs associated with the Proposed New Source Performance Standard.

EPA estimates that industry will not incur incremental MR&R costs due to the Proposed Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units. This is because this action imposes no new MR&R burden on designated facilities after final rule promulgation beyond what those facilities would already be subject to under the authorities of 40 CFR parts 75 and 98. We estimate that states will incur MR&R costs associated with these proposals. We estimate that this may affect 50 states, resulting in a total national annual burden of approximately 104,000 hours of labor, or approximately $12 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 this action. For purposes of this analysis, we estimate that these costs may begin as early as 2024 and continue through 2042.

[55] For purposes of this analysis, we assume: (1) In 2019 dollars, costs in 2025 are approximately $13,000, based on the TTTTa supporting statement in the docket; (2) Beginning in 2026, the costs per unit are approximately $3,800 in 2019 dollars, which is the average cost per unit associated with subpart TTTT; (3) We assume 16 additional new respondents per year starting in 2026, which results in an additional cost of approximately $61,000 each year in 2019 dollars.

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

	Proposed NSPS for New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units		Proposed EGs for Existing Fossil Fuel-Fired Electric Generating Units		Total
	Industry	State[a]	Industry[b]	State	Total
2024	-	-	-	12	12
2025	0.013	-	-	12	12
2026	0.075	-	-	12	12
2027	0.14	-	-	12	13
2028	0.20	-	-	12	13
2029	0.26	-	-	12	13
2030	0.32	-	-	12	13
2031	0.38	-	-	12	13
2032	0.44	-	-	12	13
2033	0.50	-	-	12	13
2034	0.57	-	-	12	13
2035	0.63	-	-	12	13
2036	0.69	-	-	12	13
2037	0.75	-	-	12	13
2038	0.81	-	-	12	13
2039	0.87	-	-	12	13
2040	0.94	-	-	12	13
2041	1.0	-	-	12	13
2042	1.1	-	-	12	13

[a] EPA estimates that states will not incur MR&R costs for the Proposed 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 Proposed 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 proposed NSPS and Emissions 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.

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.[56]

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.[57]

IPM also endogenously models the partial equilibrium of coal supply and EGU coal demand levels throughout the contiguous U.S., taking into account assumed non-power sector demand and imports/exports. IPM reflects 36 coal supply regions, 14 coal grades, and the coal transport network, which consists of over four thousand linkages representing rail, barge, and truck and conveyer linkages. The coal supply curves in IPM were developed during a thorough bottom-up, mine-by-mine approach that depicts the coal choices and associated supply costs that power plants would face if selecting that coal over the modeling time horizon. The IPM documentation outlines the methods and data used to quantify the economically recoverable coal reserves, characterize their cost, and build the 36 coal regions' supply curves.[58]

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

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

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

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

capital.[59] 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.[60]

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 stakeholders, including owners and operators of capacity in the electricity sector that is represented by the model, public interest groups, and other developers of U.S. electricity sector models. The feedback that the Agency receives provides a highly detailed review of key input assumptions, model representation, and modeling results. IPM has received extensive review by energy and environmental modeling experts in a variety of contexts. For example, in October 2014 U.S. EPA commissioned a peer review of EPA Baseline version 5.13 using the Integrated Planning Model. [61] Additionally, and in the late 1990s, the Science Advisory Board reviewed

[59] See Chapter 10 of the IPM documentation, available at: https://www.epa.gov/airmarkets/power-sector-modeling
[60] Costs modeled in IPM reflect the costs faced by industry, and therefore are net of subsidies included in the IRA
[61] See Response and Peer Review Report EPA Baseline run Version 5.13 Using IPM, available at: https://www.epa.gov/airmarkets/response-and-peer-review-report-epa-base-case-version-513-using-ipm.

IPM as part of the CAA Amendments Section 812 prospective studies.[62] 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.[63] 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.[64]

3.5.1 EPA's IPM Baseline Run v6.21

For our analysis of the proposed NSPS, and the proposed Emissions Guidelines, EPA used the post-IRA 2022 reference case version of IPM, as well as a companion updated database of EGU units (the National Electricity Energy Data System or NEEDS 10-14-22) that is used in EPA's modeling applications of IPM.[65] The IPM Baseline includes the CSAPR, CSAPR Update, the Revised CSAPR Update, and the proposed Good Neighbor Plan for 2015 Ozone NAAQS, as well as the Mercury and Air Toxics Standards. The baseline also includes the 2015 Effluent

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

[63] 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).

[64] 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.

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

Limitation Guidelines (ELG) and the 2015 Coal Combustion Residuals (CCR), and the finalized 2020 ELG and CCR rules.[66] 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 Proposed 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.[67] 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 generation, energy storage, and CCS. The model runs for the main RIA analysis examine the combined effects of the proposed NSPS, and the proposed 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 proposed NSPS, and the proposed Emissions Guidelines, EPA conducted quantitative analysis of the three illustrative scenarios: the proposal and a more and a less stringent scenario. 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

[66] For a full list of modeled policy parameters, please see: https://www.epa.gov/airmarkets/power-sector-modeling
[67] 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

by the 2030 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.[68] 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.

While CCS at new and existing sources and co-firing natural gas at existing coal facilities 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.

By the next decade, costs for low-GHG hydrogen are expected to be competitive with higher-GHG forms of hydrogen given declines due to learning and the IRC section 45V subsidies. Given the tax credits in IRC section 45V(b)(2)(D) of \$3/kg H_2 for hydrogen with GHG emissions of less than 0.45 kg CO_2e/kg H_2, and substantial DOE grant programs to drive down costs of clean hydrogen, some entities project the delivered costs of electrolytic low-GHG hydrogen to range from \$1/kg H_2 to \$0/kg H_2 or less.[69, 70, 71 72] These projections are more optimistic than, but still comparable to, 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.[73] 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

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68 For details, please see sections VII, VIII and X of the preamble.

69 "US green hydrogen costs to reach sub-zero under IRA: longer-term price impacts remain uncertain," S&P Global Commodity Insights, September 29, 2022.

70 "DOE Funding Opportunity Targets Clean Hydrogen Technologies" American Public Power, January 31, 2023.

71 With the 45V PTC, delivered costs of hydrogen are projected to fall in the range of \$0.70/kg to \$1.15/kg for power sector applications.

72 "Treeprint: US Inflation Reduction Act – A tipping point in climate action," Credit Suisse, November 2022. See: https://www.credit-suisse.com/treeprintusinflationreductionact

73 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

down costs even further over the next decade.[74] [75] [76] The combination of competitive pricing and widespread net-zero commitments throughout the utility and merchant electricity generation market has the potential to drive future hydrogen co-firing applications to be low-GHG hydrogen.[77] EPA is therefore soliciting comment on whether low-GHG hydrogen needs to be defined as part of the BSER in this proposed rulemaking.

Hydrogen is an exogenous input to the model, represented as a fuel that is available at affected sources at a delivered cost of $1/kg under the baseline, and at a delivered cost of $0.5/kg in years when the second phase of the proposed NSPS is assumed to be active. These costs are inclusive of $3/kg subsidies under the IRA. The second phase of the proposed NSPS is assumed to provide investment certainty to produce hydrogen for use in power sector applications, resulting in lower realized costs.[78] These hydrogen subsidies, as well as subsidies for other technologies such as renewables and CCS, are important factors in sector decision-making in the baseline as well as under the illustrative scenarios modeled in this RIA. 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 Proposal scenario, incremental electricity demand from hydrogen production in 2035 is estimated at about 108 TWh, or approximately 2 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 proposed 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 Agency's computable general equilibrium model, SAGE. The economy-wide

[74] "Sound waves boost green hydrogen production," Power Engineering, January 4, 2023.
[75] "Direct seawater electrolysis by adjusting the local reaction environment of a catalyst," Nature Energy, January 30, 2023.
[76] Hydrogen from Next-generation Electrolyzers of Water (H2NEW) | H2NEW (energy.gov)
[77] 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
[78] For details on the cost assumptions for hydrogen, please see the sections VII of the preamble.

analysis is considered a complement to the more detailed evaluation of sector costs produced by IPM.

The annualized social costs estimated in SAGE are approximately 35 percent larger than the partial equilibrium private compliance costs (less taxes and transfers) derived from IPM. This is consistent with general expectations based on the empirical literature (e.g., Marten et al., 2019). However, the social cost estimate reflects the combined effect of the proposed rules' requirements and interactions with IRA subsidies for specific technologies that are expected to see increased use in response to the proposed rules. We are not able to identify their relative roles at this time. See Section 5.2 and Appendix B for more discussion on estimates of private and social costs. While the SAGE model has been peer reviewed by the EPA's Science Advisory Board (SAB), this represents the first time it has been used in a regulatory context. As such, EPA requests comment on its use in section XIV(C) of the preamble to these proposed rules.

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 2042, 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 3-4 presents the estimated reduction in power sector CO_2 emissions resulting from compliance with the evaluated illustrative scenarios. The emission reductions follow an expected pattern: the less stringent alternative produces smaller emissions reductions than the proposal, and the more stringent alternative results in more CO_2 emissions reductions.

Table 3-5 EGU Annual CO_2 Emissions and Emissions Changes (million metric tons) for the Baseline and the Illustrative Scenarios from 2028 through 2040 [79]

Annual CO_2	Total Emissions				Change from Baseline		
(million metric tons)	Baseline	Proposal	Less Stringent	More Stringent	Proposal	Less Stringent	More Stringent
2028	1,222	1,212	1,214	1,222	-10	-9	0
2030	972	882	889	865	-89	-83	-107
2035	608	572	573	566	-37	-35	-42
2040	481	458	459	459	-24	-22	-23

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 2030 across all scenarios, reflective of the start of the requirements on existing coal-fired EGUs. Under the proposal and less stringent scenarios, the second phase of the NSPS is assumed to begin in the 2035 run year, while the second phase of the NSPS is assumed to begin in 2030 under the more stringent scenario. 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 2030 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.

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

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

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, $PM_{2.5}$, and Ozone NO_X for the Illustrative Scenarios for 2028 to 2040

Annual NO_X	**Total Emissions**				**Change from Baseline**		
(Thousand Tons)	**Baseline**	**Proposal**	**Less Stringent**	**More Stringent**	**Proposal**	**Less Stringent**	**More Stringent**
2028	457	449	450	460	-7	-7	3
2030	368	304	307	306	-64	-61	-61
2035	214	193	194	192	-21	-20	-22
2040	162	149	150	149	-13	-12	-13
Ozone Season NO_X[a]	**Total Emissions**				**Change from Baseline**		
(Thousand Tons)	**Baseline**	**Proposal**	**Less Stringent**	**More Stringent**	**Proposal**	**Less Stringent**	**More Stringent**
2028	195	191	192	196	-3	-3	1
2030	163	142	143	143	-22	-20	-20
2035	104	97	97	97	-7	-7	-7
2040	80	76	76	76	-4	-4	-4
Annual SO_2	**Total Emissions**				**Change from Baseline**		
(Thousand Tons)	**Baseline**	**Proposal**	**Less Stringent**	**More Stringent**	**Proposal**	**Less Stringent**	**More Stringent**
2028	394	382	385	390	-12	-9	-4
2030	282	175	183	169	-107	-99	-114
2035	130	89	92	89	-41	-38	-41
2040	89	59	62	59	-30	-27	-30
Direct $PM_{2.5}$	**Total Emissions**				**Change from Baseline**		
(Thousand Tons)	**Baseline**	**Proposal**	**Less Stringent**	**More Stringent**	**Proposal**	**Less Stringent**	**More Stringent**
2028	75	73	74	74	-1	-1	0
2030	66	60	60	61	-6	-5	-5
2035	47	45	45	45	-1	-1	-2
2040	38	38	38	38	-1	-1	-1

[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.[80] 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

	Proposal	Less Stringent	More Stringent
2024 to 2042 (Annualized)	0.97	0.95	0.71
2024 to 2045 (Annualized)	0.88	0.86	0.68
2028 (Annual)	-0.21	-0.19	-0.07
2030 (Annual)	4.06	4.08	3.02
2035 (Annual)	0.28	0.23	0.20
2040 (Annual)	0.76	0.71	0.51
2045 (Annual)	-0.045	-0.053	0.384

"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.[81] This does not include compliance costs beyond 2042. "2024 to 2045 (Annualized)" reflects total estimated annual compliance costs levelized over the period 2024 through 2045 and discounted using a 3.76 real discount rate. This does not include compliance costs beyond 2045. "2028 (Annual)" through "2045 (Annual)" costs reflect annual estimates in each of those run years.[82]

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, 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 objective function is to minimize the discounted present value (PV) of a stream of annual total cost of generation over a

[80] 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.

[81] 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 21-year period (2024 to 2045) using the 3.76 percent rate as well. Table 0-2 reports the PV of the annual stream of costs from 2024 to 2042 using 3 percent and 7 percent consistent with OMB guidance.

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

multi-decadal time period.[83] Under the baseline, the proposed GNP rule results in installation of SCR controls in the 2028 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. Costs peak in 2030 across all scenarios, reflecting the date of imposition of the proposed Emission Guidelines for coal-fired steam generating units. Costs under the more stringent scenario are projected to be lower than under the less-stringent scenario and the proposal in 2030. This is due to the assumption (as discussed in Section 3.5.2: Methodology for Evaluating the Illustrative Scenarios) that when the second phase of the NSPS is active, hydrogen costs (represented exogenously in the modeling) are assumed to be \$0.5/kg rather than \$1/kg otherwise. Under the proposal and less stringent scenarios, the second phase of the NSPS is assumed to be active in 2035, while under the more stringent scenario, the second phase of the NSPS is assumed to be active in 2030. The lower input fuel price in 2030 under the more stringent scenario therefore drives total compliance costs lower than under the other two scenarios. In 2035, costs are similar across all scenarios, reflecting similar hydrogen price assumptions and similar compliance outcomes under the modeled policies. In general, costs decline over the forecast period.

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.[84] For this analysis we first calculated the PV of the stream of costs from 2024 through 2045[85] 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

[83] For more information, please see Chapter 2 of the IPM documentation.
[84] 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.
[85] 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).[86] After calculating the PV of the cost streams, the same 3.76 percent discount rate and 2024 to 2045 time period are used to calculate the levelized annual (i.e., annualized) cost estimates shown in Table 3-7.[87] The same approach was used to develop the annualized cost estimates for the 2024 to 2042 timeframe. Additionally, note that the 2028 to 2042 and 2028 to 2045 equivalent annualized compliance cost estimates have the expected relationship to each other; the annualized costs are lowest for the more stringent alternative (driven by the assumption of earlier lower cost hydrogen availability).

3.6.3 Impacts on Fuel Use, Prices and Generation Mix

The proposed NSPS, and the proposed 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 and 2040 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, and 2040 run years. These fuel use estimates reflect some power companies choosing to shift to natural gas and renewables from coal in 2030 rather than implement available cost-reasonable controls as a result of the imposition of GHG mitigation measures under the proposed Emissions Guidelines for coal-fired steam generating units. Under the proposal and less stringent scenario, in the 2035 run year, natural gas consumption increases are less than in the 2030 run year, reflective of the imposition of the second phase of the NSPS. Under the more stringent scenario, the second phase of the NSPS is assumed to be active in 2030, which reduces the total amount of increase in gas consumption in that year relative to the other scenarios. By 2040, total coal and gas consumption are at similar

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[86] 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."

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

levels across the three scenarios, reflecting similar GHG mitigation measure imposition at similar source categories by that year.

To put these reductions into context, under the Baseline, power sector coal consumption is projected to decrease from 252 million tons in 2028 to 176 million tons in 2030 (15 percent annually between 2028-2030), and to 80 million tons in 2035 (11 percent annually between 2030-2035). Under the proposal, coal consumption is projected to decrease from 246 million tons in 2028 to 105 million tons in 2028 (29 percent annually between 2028-2030), and 62 million tons in 2035 (8 percent annually between 2030-2035). Between 2015 and 2020, annual coal consumption in the electric power sector fell between 8 and 19 percent annually.[88]

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

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

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

		Million Tons				Percent Change from Baseline		
	Year	Baseline	Proposal	Less Stringent	More Stringent	Proposal	Less Stringent	More Stringent
Appalachia	2028	48	48	48	50	-2%	0%	2%
Interior		51	49	49	50	-4%	-4%	-1%
Waste Coal		4	4	4	4	0%	0%	0%
West		148	145	145	147	-2%	-2%	-1%
Total		252	246	247	251	-2%	-2%	0%
Appalachia	2030	28	19	21	19	-31%	-27%	-34%
Interior		37	31	30	31	-17%	-17%	-16%
Waste Coal		4	3	3	3	-32%	-33%	-30%
West		107	52	56	50	-51%	-47%	-53%
Total		176	105	110	103	-40%	-38%	-42%
Appalachia	2035	11	10	10	10	-8%	-4%	-8%
Interior		20	21	22	21	9%	10%	6%
Waste Coal		2	0	0	0	-83%	-85%	-79%
West		48	30	30	31	-37%	-36%	-36%
Total		80	62	63	62	-23%	-22%	-23%
Appalachia	2040	6	7	8	7	34%	36%	19%
Interior		16	19	20	19	25%	26%	25%
Waste Coal		2	0	0	0	-100%	-100%	-100%
West		39	26	26	26	-33%	-33%	-32%
Total		62	53	53	52	-15%	-14%	-15%

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

Trillion Cubic Feet					Percent Change from Baseline		
Year	Baseline	Proposal	Less Stringent	More Stringent	Proposal	Less Stringent	More Stringent
2028	12.5	12.6	12.6	12.6	0%	0%	0%
2030	12.6	13.6	13.5	13.3	8%	7%	5%
2035	9.9	9.9	9.8	9.7	-1%	-1%	-2%
2040	8.1	7.9	7.9	7.9	-2%	-2%	-2%

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

	Trillion Btu			
Year	Baseline	Proposal	Less Stringent	More Stringent
2028	0	0	0	0
2030	0	3	3	531
2035	0	294	295	458
2040	0	347	345	388

Table 3-11 and Table 3-12 present the projected coal and natural gas prices in 2030, 2035 and 2040, as well as the percent change from the baseline projected due to the illustrative scenarios. In 2030, gas prices are higher, which is reflective of higher gas consumption as a result of the imposition of the proposed Emission Guidelines for coal-fired steam generating units. In 2035, the second phase of the NSPS is assumed to be active, resulting in less gas consumption and lower prices. Under the more stringent scenario, the second phase of the NSPS is assumed to be active in 2030, resulting in smaller increases in gas consumption in that year relative to the other scenarios and consequently smaller increases in natural gas prices.

Table 3-11 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	Proposal	Less Stringent	More Stringent	Proposal	Less Stringent	More Stringent
Minemouth	2028	1.16	1.16	1.16	1.16	0%	0%	0%
Delivered	2028	1.59	1.58	1.58	1.59	-1%	-1%	0%
Minemouth	2030	1.17	1.27	1.26	1.27	8%	8%	8%
Delivered	2030	1.47	1.47	1.48	1.46	0%	1%	0%
Minemouth	2035	1.34	1.41	1.41	1.41	5%	5%	5%
Delivered	2035	1.38	1.40	1.40	1.39	2%	2%	1%
Minemouth	2040	1.42	1.49	1.49	1.49	5%	4%	4%
Delivered	2040	1.42	1.45	1.45	1.45	2%	2%	1%

Table 3-12 2028, 2030, 2035 and 2040 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	Proposal	Less Stringent	More Stringent	Proposal	Less Stringent	More Stringent
Henry Hub	2028	3.0	3.0	3.0	3.0	0%	0%	0%
Delivered		3.0	3.0	3.0	3.0	0%	0%	0%
Henry Hub	2030	2.4	2.6	2.6	2.6	10%	10%	7%
Delivered		2.5	2.8	2.8	2.7	9%	9%	5%
Henry Hub	2035	1.9	1.8	1.8	1.8	-2%	-2%	-2%
Delivered		2.1	2.0	2.0	2.0	-2%	-2%	-3%
Henry Hub	2040	2.0	2.0	2.0	2.0	-2%	-2%	-2%
Delivered		2.2	2.1	2.1	2.1	-3%	-2%	-3%

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 2030 reflecting the imposition of the proposed Emissions Guidelines and are smaller thereafter. 45(q) is available for 12 years within the modeling, after which point units no longer receive tax credits and must dispatch based on unsubsidized operating costs.

Table 3-13 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	Proposal	Less Stringent	More Stringent	Proposal	Less Stringent	More Stringent
Coal	2028	484	472	474	482	-2%	-2%	0%
Coal & CCS		0	0	0	0	-	-	-
Nat. Gas co-firing		0	0	0	0	-	-	-
Nat. Gas		1,773	1,783	1,781	1,773	1%	0%	0%
H_2 co-firing		0	0	0	0	-	-	-
Nat. Gas & CCS		0	0	0	0	-	-	-
Nuclear		765	765	765	765	0%	0%	0%
Hydro		294	294	294	294	0%	0%	0%
Non-Hydro RE		964	966	966	966	0%	0%	0%
Oil/Gas Steam		30	30	30	30	0%	-1%	1%
Other		30	30	30	30	0%	0%	0%
Grand Total		4,341	4,341	4,341	4,341	0%	0%	0%
Coal	2030	243	80	78	78	-67%	-68%	-68%
Coal & CCS		66	85	84	85	29%	28%	28%
Nat. Gas co-firing		0	5	28	5	-	-	-
Nat. Gas		1,722	1,846	1,836	1,715	7%	7%	0%
H_2 co-firing		0	2	2	134	-	-	-
Nat. Gas & CCS		50	31	31	26	-37%	-38%	-48%
Nuclear		734	734	734	734	0%	0%	0%
Hydro		303	303	303	302	0%	0%	0%
Non-Hydro RE		1,269	1,278	1,277	1,273	1%	1%	0%
Oil/Gas Steam		33	50	41	59	52%	25%	79%
Other		29	29	29	29	0%	0%	0%
Grand Total		4,447	4,442	4,443	4,439	0%	0%	0%
Coal	2035	44	0	1	0	-100%	-99%	-100%
Coal & CCS		75	85	85	85	13%	13%	12%
Nat. Gas co-firing		0	1	5	1	-	-	-
Nat. Gas		1,325	1,290	1,288	1,234	-3%	-3%	-7%
H_2 co-firing		0	70	70	133	-	-	-
Nat. Gas & CCS		77	60	59	56	-22%	-23%	-27%
Nuclear		660	660	660	660	0%	0%	0%
Hydro		329	328	328	329	0%	0%	0%
Non-Hydro RE		2,180	2,186	2,187	2,181	0%	0%	0%
Oil/Gas Steam		16	18	17	19	13%	1%	17%
Other		29	29	29	29	0%	0%	0%
Grand Total		4,736	4,728	4,728	4,728	0%	0%	0%

Coal	2040	24	0	1	0	-99%	-98%	-99%
Coal & CCS		55	65	65	64	19%	19%	17%
Nat. Gas co-firing		0	0	2	0	-	-	-
Nat. Gas		1,087	1,044	1,043	1,006	-4%	-4%	-7%
H_2 co-firing		0	75	75	122	-	-	-
Nat. Gas & CCS		77	54	54	52	-29%	-30%	-33%
Nuclear		616	616	616	616	0%	0%	0%
Hydro		346	346	346	346	0%	0%	0%
Non-Hydro RE		2,826	2,818	2,818	2,814	0%	0%	0%
Oil/Gas Steam		3	3	3	3	-3%	-19%	1%
Other		28	28	28	28	0%	0%	0%
Grand Total		5,061	5,050	5,050	5,051	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 and 2040 by primary fuel type. In 2030, the proposed Emissions Guidelines is assumed to be in effect under all three scenarios. Under the proposal, 45 GW of coal-fired EGUs have committed retirements by 2035 and operate at an annual capacity factor of 20 percent or less in 2030, and as such are subject to the near-term existing coal-fired steam generating units subcategory. One GW of coal-fired EGUs have committed to retirement by 2040 are subject to the medium-term existing coal-fired steam generating units and are subject to 40 percent natural gas co-firing requirement. 12 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 3 GW incremental to the baseline). Finally, 21 GW of coal-fired EGUs undertake coal to gas conversion (9 GW incremental to the baseline).

Under the baseline, total coal retirements between 2023 and 2035 are projected to be 104 GW (or 15 GW annually). Under the proposed rules, total coal retirements between 2023 and 2035 are projected to be 126 GW (or 18 GW annually). This is compared to an average recent historical retirement rate of 11 GW per year from 2015 – 2020.[89]

By 2030 the proposal is projected to result in an additional 1 GW of coal retirements, by 2035 an incremental 23 GW of coal retirements and by 2040 an incremental 18 GW of coal retirements relative to the baseline. These compliance decisions reflect EGU operators making

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

least-cost decisions on how to achieve efficient compliance with the rules while maintaining sufficient generating capacity to ensure grid reliability.[90]

An incremental 2 GW of renewable capacity additions is projected by 2035 (consisting primarily of solar capacity builds) in the illustrative proposal scenario. Under the proposal, 25 GW of economic NGCC additions occur by 2035 (300 MW incremental to the baseline), and 43 GW of economic NGCT additions occur by 2035 (23 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, 6 GW of NGCCs and 5 GW of NGCT additions co-fire hydrogen 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.

[90] 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.

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

		Capacity (GW)				Percent Change from Baseline		
	Year	Baseline	Proposal	Less Stringent	More Stringent	Proposal	Less Stringent	More Stringent
Coal	2028	100	99	99	99	-2%	-1%	-1%
Coal & CCS		0	0	0	0	-	-	-
Nat. Gas co-firing		0	0	0	0	-	-	-
Nat. Gas		463	467	466	466	1%	1%	1%
H_2 co-firing		0	0	0	0	-	-	-
Nat. Gas & CCS		0	0	0	0	-	-	-
Nuclear		96	96	96	96	0%	0%	0%
Hydro		102	102	102	102	0%	0%	0%
Non-Hydro RE		315	316	316	316	0%	0%	0%
Oil/Gas Steam		63	63	63	63	0%	0%	1%
Other		7	7	7	7	0%	0%	0%
Grand Total		1,146	1,149	1,149	1,149	0%	0%	0%
Coal	2030	60	46	44	44	-23%	-26%	-26%
Coal & CCS		9	12	12	12	30%	29%	29%
Nat. Gas co-firing		0	1	6	1	-	-	-
Nat. Gas		454	460	460	445	1%	1%	-2%
H_2 co-firing		0	0	0	19	-	-	-
Nat. Gas & CCS		7	4	4	3	-37%	-38%	-48%
Nuclear		92	92	92	92	0%	0%	0%
Hydro		104	104	104	104	0%	0%	0%
Non-Hydro RE		403	405	405	404	0%	0%	0%
Oil/Gas Steam		60	69	67	69	15%	10%	14%
Other		7	7	7	7	0%	0%	0%
Grand Total		1,196	1,200	1,200	1,200	0%	0%	0%
Coal	2035	33	0	1	0	-99%	-97%	-99%
Coal & CCS		11	12	12	12	13%	13%	13%
Nat. Gas co-firing		0	1	6	1	-	-	-
Nat. Gas		460	476	473	469	4%	3%	2%
H_2 co-firing		0	11	11	20	-	-	-
Nat. Gas & CCS		10	8	8	8	-22%	-23%	-27%
Nuclear		84	84	84	84	0%	0%	0%
Hydro		108	108	108	108	0%	0%	0%
Non-Hydro RE		668	670	670	668	0%	0%	0%
Oil/Gas Steam		59	67	64	67	13%	8%	14%
Other		7	7	7	7	0%	0%	0%
Grand Total		1,439	1,443	1,443	1,443	0%	0%	0%

Coal	2040	28	0	1	0	-99%	-97%	-99%
Coal & CCS		8	9	9	9	20%	19%	18%
Nat. Gas co-firing		0	0	6	0	-	-	-
Nat. Gas		503	512	509	506	2%	1%	1%
H_2 co-firing		0	13	13	20	-	-	-
Nat. Gas & CCS		10	8	8	8	-22%	-23%	-27%
Nuclear		79	79	79	79	0%	0%	0%
Hydro		110	110	110	110	0%	0%	0%
Non-Hydro RE		868	867	867	865	0%	0%	0%
Oil/Gas Steam		59	67	64	67	14%	8%	14%
Other		7	7	7	7	0%	0%	0%
Grand Total		1,672	1,672	1,672	1,671	0%	0%	0%

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).[91] 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 EIA electricity market data for each of the 25 electricity supply regions in the electricity market module of the National Energy Modeling System (NEMS).[92]

Table 3-15, Table 3-16, and Table 3-17 present the projected percentage changes in the retail price of electricity for the three illustrative scenarios in 2030, 2035 and 2040, 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 2030. National electricity rates are projected to increase 2 percent above baseline levels in 2030, or an increase of 2 mills/kWh (2019 dollars). In 2035, EPA estimates that these rules will result in a 0.24 percent increase in national average retail electricity price, or by about 0.22 mills/kWh (2019

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

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

dollars). In 2040, EPA estimates that these rules will result in a 0.08 percent increase in national average retail electricity price, or by about 0.07 mills/kWh.

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**	**Proposal**	**Less Stringent**	**More Stringent**	**Proposal**	**Less Stringent**	**More Stringent**
TRE	78	81	81	80	3%	3%	2%
FRCC	89	90	90	90	2%	2%	1%
MISW	80	82	82	82	2%	2%	1%
MISC	89	92	92	91	3%	3%	2%
MISE	97	100	100	102	4%	4%	5%
MISS	89	91	91	91	2%	2%	2%
ISNE	147	148	148	148	1%	1%	1%
NYCW	202	205	205	205	1%	1%	1%
NYUP	122	124	124	123	2%	2%	1%
PJME	102	105	105	105	4%	4%	4%
PJMW	94	97	97	98	3%	3%	4%
PJMC	78	82	82	83	5%	5%	6%
PJMD	72	75	74	75	3%	3%	4%
SRCA	97	98	98	98	1%	1%	1%
SRSE	90	92	92	91	2%	2%	1%
SRCE	105	106	106	105	1%	1%	0%
SPPS	69	69	69	69	0%	1%	-1%
SPPC	80	81	81	81	1%	1%	1%
SPPN	60	64	64	64	8%	8%	8%
SRSG	83	84	84	84	1%	1%	1%
CANO	155	155	156	155	0%	0%	0%
CASO	187	187	187	186	0%	0%	0%
NWPP	74	75	75	75	1%	1%	2%
RMRG	86	88	88	89	2%	2%	3%
BASN	88	88	88	88	-1%	0%	-1%
NATIONAL	97	99	99	99	2%	2%	2%

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**	**Proposal**	**Less Stringent**	**More Stringent**	**Proposal**	**Less Stringent**	**More Stringent**
TRE	68	68	68	68	0%	0%	0%
FRCC	81	81	81	81	0%	0%	0%
MISW	80	81	81	81	0%	0%	0%
MISC	80	80	80	80	0%	0%	0%
MISE	89	89	89	89	0%	0%	0%
MISS	84	85	85	84	0%	0%	0%
ISNE	150	151	151	151	0%	0%	0%
NYCW	187	188	188	188	0%	0%	1%
NYUP	107	107	107	107	0%	0%	1%
PJME	105	106	106	106	1%	1%	1%
PJMW	82	83	83	83	1%	1%	1%
PJMC	82	85	85	84	3%	3%	3%
PJMD	73	74	74	74	0%	0%	1%
SRCA	93	93	93	93	0%	0%	0%
SRSE	114	113	113	113	0%	0%	0%
SRCE	69	69	69	69	0%	0%	0%
SPPS	70	71	71	71	0%	0%	0%
SPPC	68	68	68	68	0%	0%	0%
SPPN	63	65	65	65	4%	4%	4%
SRSG	94	93	93	92	-1%	-1%	-2%
CANO	151	150	150	150	0%	0%	-1%
CASO	178	178	178	178	0%	0%	0%
NWPP	80	80	80	80	0%	0%	0%
RMRG	92	91	91	91	0%	0%	-1%
BASN	78	80	80	80	2%	2%	2%
NATIONAL	93	93	93	93	0%	0%	0%

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**	**Proposal**	**Less Stringent**	**More Stringent**	**Proposal**	**Less Stringent**	**More Stringent**
TRE	68	68	68	68	0%	0%	0%
FRCC	86	86	86	86	0%	0%	0%
MISW	90	90	90	90	0%	0%	0%
MISC	68	69	69	69	0%	0%	0%
MISE	89	90	90	90	0%	0%	0%
MISS	79	79	79	79	0%	0%	0%
ISNE	150	150	150	150	0%	0%	0%
NYCW	203	203	203	203	0%	0%	0%
NYUP	119	119	119	119	0%	0%	0%
PJME	110	110	110	110	0%	0%	0%
PJMW	80	81	81	81	0%	0%	1%
PJMC	75	76	76	76	1%	1%	1%
PJMD	75	75	75	75	0%	0%	0%
SRCA	120	120	120	120	0%	0%	0%
SRSE	77	77	77	77	0%	0%	0%
SRCE	83	83	83	83	0%	0%	0%
SPPS	60	60	60	60	0%	0%	0%
SPPC	72	73	73	73	0%	0%	0%
SPPN	70	70	70	70	0%	0%	0%
SRSG	86	86	86	86	0%	0%	0%
CANO	151	151	151	150	0%	0%	0%
CASO	183	181	181	180	-1%	-1%	-2%
NWPP	83	84	84	83	0%	0%	0%
RMRG	79	79	79	79	0%	0%	-1%
BASN	85	87	86	87	2%	2%	2%
NATIONAL	93	93	93	93	0%	0%	0%

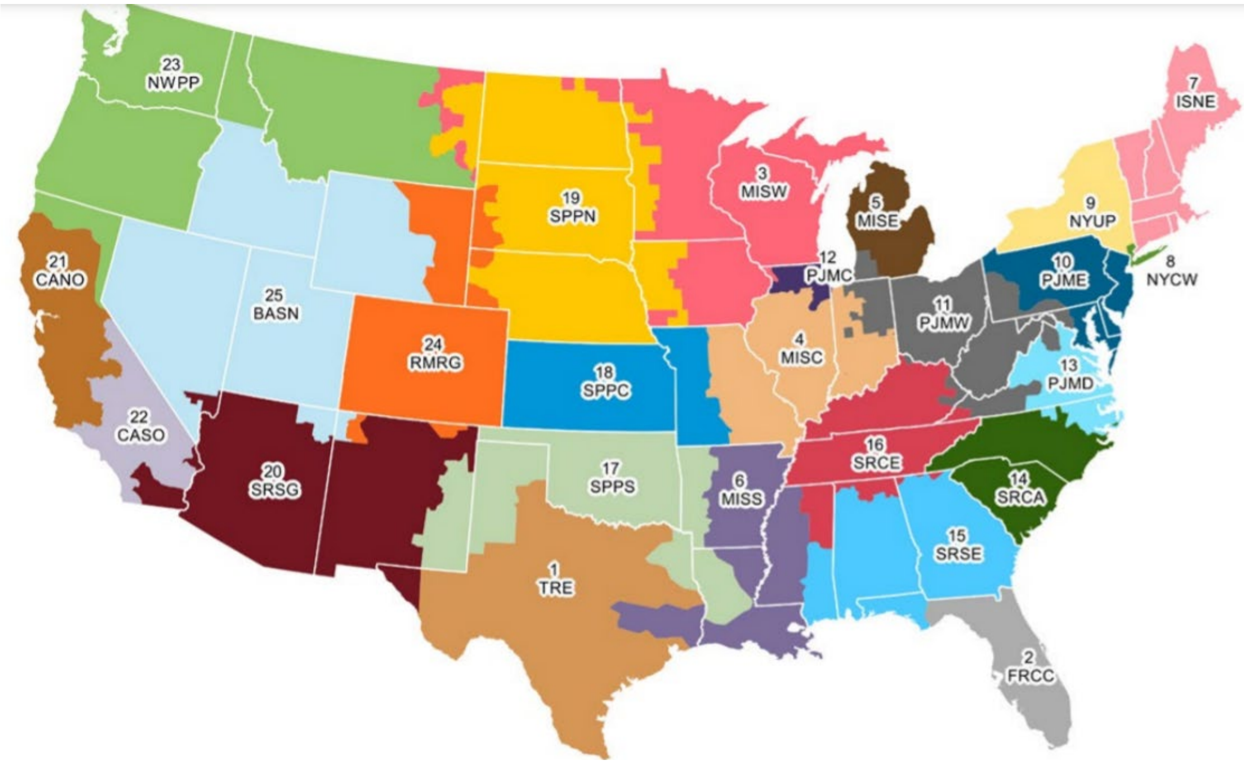

Figure 3-1 Electricity Market Module Regions
Source: EIA (http://www.eia.gov/forecasts/aeo/pdf/nerc_map.pdf)

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.

EPA's modeling did not include impacts of the proposed 111(d) standards on existing natural gas-fired EGUs or some elements of the proposed 111(b)[93] standards on new natural gas-fired EGUs. These requirements are analyzed separately in Section 8 of this RIA.

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 2021 reference case with incremental demand from EPA's OTAQ's on the books rules that are not captured in AEO 2021 reference case projections.[94] To the extent electric demand is higher or lower, it may increase/decrease the projected future composition of the fleet.

• Natural gas supply and demand: The recent run up in fuel costs is assumed to abate by the first run year in this analysis (2028). Large increases in supply over the last few years, and relatively low prices, are represented in the analysis for subsequent run years. To the extent prices are higher or lower, it would influence the use of natural gas for electricity generation and overall competitiveness of other EGUs (e.g., coal and nuclear units).

• Longer-term planning by utilities: Many utilities have announced long-term clean energy and/or climate commitments, with a phasing out of large amounts of coal capacity by 2030 and continuing through 2050. These announcements, some of which are not legally binding, are not necessarily reflected in the baseline, and may alter the amount of coal capacity projected in the baseline that would be covered under this rule.

• Inflation Reduction Act (IRA): The IRA was passed in August of 2022. 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 proposed rules as modeled in this RIA on that

[93] Specifically, the requirement for new gas-fired capacity operating at greater than 50 percent annual capacity factor in run year 2040 to increase Hydrogen co-firing to 96 percent by volume or convert to CCS was not modeled.
[94] For details, see chapter 3 of the IPM documentation available at: https://www.epa.gov/power-sector-modeling

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.[95]

• 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/kg under the baseline, and at a delivered cost of $0.5/kg in years when the second phase of the NSPS is assumed to be active. The model does not track any upstream emissions[96] associated with the production of the hydrogen, nor any incremental electricity demand associated with its production.[97] The incorporation of these effects could change the amount of hydrogen selected as a compliance measure. The model also does not account for any possible increases in NO_X emission rates at higher levels of hydrogen blending.[98] 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. However, plants may adopt compliance methods that are different than those represented in the baseline.

The impact of the Proposed Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector

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

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

[97] 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.

[98] 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.

Climate Review[99] 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.

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 proposed NSPS and Emissions 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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[99] 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

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4 BENEFITS ANALYSIS

4.1 Introduction

The proposed rules are expected to reduce emissions of carbon dioxide (CO_2), nitrogen oxides (NO_X), fine particulate matter ($PM_{2.5}$), and sulfur dioxide (SO_2) nationally. 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.[100]

The section describes the methods used to estimate the climate benefits from reductions of CO_2 emissions. This analysis uses estimates of the social cost of greenhouse gases to monetize the estimated changes in CO_2 emissions expected to occur over 2028 through 2042 for the illustrative scenarios. In principle, SC-GHG 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-GHG therefore, reflects the societal value of reducing emissions of the gas in question by one metric ton and is the theoretically appropriate value to use in conducting benefit-cost analyses of policies that affect GHG emissions.

This section also describes the methods used to estimate the benefits to human health of reducing 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 (EPA, 2020; U.S. EPA, 2019b, 2020a, 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 and 2040 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 2042, using the model surfaces for 2028,

[100] Section 4 pertains to the analysis of the proposed standards for new natural gas-fired EGUs and for existing coal-fired EGUs. Please see Section 8 for impact analysis of the proposed standards for existing natural gas-fired EGUs and the third phase of the proposed standards for new natural gas-fired EGUs.

2030, 2035 and 2040 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 and 2040 for each of the three illustrative scenarios (i.e., proposal, less stringent scenario, and more stringent 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 proposed 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 6.2.

4.2 Climate Benefits

We estimate the social benefits of CO_2 reductions expected to occur as a result of the illustrative scenarios using estimates of the social cost of greenhouse gases (SC-GHG), specifically using the social cost of carbon (SC-CO_2). The SC-GHG is the monetary value of the net harm to society associated with a marginal increase in GHG emissions in a given year, or the benefit of avoiding that increase. In principle, SC-GHG 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-GHG therefore, reflects the societal value of reducing emissions of the gas in question by one metric ton and is the theoretically appropriate value to use in conducting benefit-cost analyses of policies that affect GHG emissions. In practice, data and modeling limitations naturally restrain the ability of SC-GHG estimates to include all the important physical, ecological, and economic impacts of climate change, such that the estimates are a partial accounting of climate change impacts and will therefore, tend to be underestimates of the marginal benefits of abatement. EPA and other Federal agencies began regularly incorporating SC-GHG estimates in their benefit-cost analyses conducted under Executive Order (E.O.) 12866[101] since 2008, following a Ninth Circuit Court of Appeals remand of a rule for failing to monetize the benefits of reducing CO_2 emissions in that rulemaking process.

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

In a first-day executive order (E.O. 13990), Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis, President Biden called for a renewed focus on updating estimates of the social cost of greenhouse gases (SC-GHG) to reflect the latest science, noting that "it is essential that agencies capture the full benefits of reducing greenhouse gas emissions as accurately as possible." Important steps have been taken to begin to fulfill this directive of E.O. 13990. In February 2021, the Interagency Working Group on the SC-GHG (IWG) released a technical support document (hereinafter the "February 2021 SC-GHG TSD") that provided a set of IWG recommended SC-GHG estimates while work on a more comprehensive update is underway to reflect recent scientific advances relevant to SC-GHG estimation (IWG, 2021). In addition, as discussed further below, EPA has developed a draft

[101] Presidents since the 1970s have issued executive orders requiring agencies to conduct analysis of the economic consequences of regulations as part of the rulemaking development process. E.O. 12866, released in 1993 and still in effect today, requires that for all economically significant regulatory actions, an agency provide an assessment of the potential costs and benefits of the regulatory action, and that this assessment include a quantification of benefits and costs to the extent feasible. For purposes of this action, monetized climate benefits are presented for purposes of providing a complete benefit-cost analysis under E.O. 12866 and other relevant executive orders. The estimates of the monetized benefits play no part in the record basis for this action.

updated SC-GHG methodology within a sensitivity analysis in the regulatory impact analysis of EPA's November 2022 supplemental proposal for oil and natural gas emissions standards that is currently undergoing external peer review and a public comment process.[102]

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

The SC-GHG estimates presented in the February 2021 SC-GHG TSD and used in this RIA were developed over many years, using a transparent process, peer-reviewed methodologies, the best science available at the time of that process, and with input from the public. Specifically, in 2009, an interagency working group (IWG) that included EPA and other executive branch agencies and offices was established to develop estimates relying on the best available science for agencies to use. The IWG published SC- CO_2 estimates in 2010 that were developed from an ensemble of three widely cited integrated assessment models (IAMs) that estimate global climate damages using highly aggregated representations of climate processes and the global economy combined into a single modeling framework. The three IAMs were run using a common set of input assumptions in each model for future population, economic, and CO_2 emissions growth, as well as equilibrium climate sensitivity (ECS)—a measure of the globally averaged temperature response to increased atmospheric CO_2 concentrations. These estimates were updated in 2013 based on new versions of each IAM (Anthoff and Tol, 2013a, 2013b; Hope, 2013; Nordhaus, 2010).[103] In August 2016 the IWG published estimates of the

[102] See https://www.epa.gov/environmental-economics/scghg
[103] Dynamic Integrated Climate and Economy (DICE), Climate Framework for Uncertainty, Negotiation, and Distribution (FUND), and Policy Analysis of the Greenhouse Gas Effect (PAGE) 2009

social cost of methane (SC-CH_4) and nitrous oxide (SC-N_2O) using methodologies that are consistent with the methodology underlying the SC-CO_2 estimates. The modeling approach that extends the IWG SC-CO_2 methodology to non-CO_2 GHGs has undergone multiple stages of peer review. The SC-CH_4 and SC-N_2O estimates were developed by Marten et al. (2015) and underwent a standard double-blind peer review process prior to journal publication. These estimates were applied in regulatory impact analyses of EPA proposed rulemakings with CH_4 and N_2O emissions impacts. EPA also sought additional external peer review of technical issues associated with its application to regulatory analysis. Following the completion of the independent external peer review of the application of the Marten et al. (2015) estimates, EPA began using the estimates in the primary benefit-cost analysis calculations and tables for a number of proposed rulemakings in 2015 (U.S. EPA, 2015b, 2015d). EPA considered and responded to public comments received for the proposed rulemakings before using the estimates in final regulatory analyses in 2016.[104] In 2015, as part of the response to public comments received to a 2013 solicitation for comments on the SC-CO_2 estimates, the IWG announced a National Academies of Sciences, Engineering, and Medicine review of the SC-CO_2 estimates to offer advice on how to approach future updates to ensure that the estimates continue to reflect the best available science and methodologies. In January 2017, the National Academies released their final report, Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide, and recommended specific criteria for future updates to the SC-GHG 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). Shortly thereafter, in March 2017, President Trump issued Executive Order 13783, which disbanded the IWG, withdrew the previous TSDs, and directed agencies to ensure SC-GHG estimates used in regulatory analyses are consistent with the guidance contained in OMB's Circular A-4, "including with respect to the consideration of domestic versus international impacts and the consideration of appropriate discount rates" (E.O. 13783, Section 5(c)). Benefit-cost analyses following E.O. 13783 used SC-GHG estimates that attempted to focus on the specific share of climate change damages in the U.S. as captured by the models (which did not

[104] The SC-CH_4 and SC-N_2O estimates were first used in sensitivity analysis for the Proposed Rulemaking for Greenhouse Gas Emissions and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles–Phase 2 (U.S. EPA and U.S. DOT, 2015).

reflect many pathways by which climate impacts affect the welfare of U.S. citizens and residents) and were calculated using two discount rates recommended by Circular A-4, 3 percent and 7 percent.[105] All other methodological decisions and model versions used in SC-GHG calculations remained the same as those used by the IWG in 2010 and 2013, respectively.

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

As noted above, EPA participated in the IWG but has also independently evaluated the interim SC-GHG estimates published in the February 2021 SC-GHG TSD and determined they are appropriate to use here to estimate climate benefits. EPA and other agencies intend to undertake a fuller update of the SC-GHG estimates that takes into consideration the advice of the National Academies (2017) and other recent scientific literature. EPA has also evaluated the supporting rationale of the February 2021 SC-GHG TSD, including the studies and methodological issues discussed therein, and concludes that it agrees with the rationale for these estimates presented in the TSD and summarized below.

In particular, the IWG found that the SC-GHG estimates used under E.O. 13783 fail to reflect the full impact of GHG emissions in multiple ways. First, the IWG concluded that those estimates fail to capture many climate impacts that can affect the welfare of U.S. citizens and

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

residents. Examples of affected interests include direct effects on U.S. citizens and assets located abroad, international trade, and tourism, and spillover pathways such as economic and political destabilization and global migration that can lead to adverse impacts on U.S. national security, public health, and humanitarian concerns. Those impacts are better captured within global measures of the social cost of greenhouse gases.

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

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

Second, the IWG concluded that the use of the social rate of return on capital (7 percent under current OMB Circular A-4 guidance) to discount the future benefits of reducing GHG emissions inappropriately underestimates the impacts of climate change for the purposes of estimating the SC-GHG. Consistent with the findings of the National Academies (2017) and the economic literature, the IWG continued to conclude that the consumption rate of interest is the theoretically appropriate discount rate in an intergenerational context, and recommended that discount rate uncertainty and relevant aspects of intergenerational ethical considerations be accounted for in selecting future discount rates (IWG, 2010, 2013, 2016a, 2016b). Furthermore, the damage estimates developed for use in the SC-GHG are estimated in consumption-equivalent terms, and so an application of OMB Circular A-4's guidance for regulatory analysis would then use the consumption discount rate to calculate the SC-GHG. EPA agrees with this assessment and will continue to follow developments in the literature pertaining to this issue. EPA also notes that while OMB Circular A-4, as published in 2003, recommends using 3 percent and 7 percent discount rates as "default" values, Circular A-4 also reminds agencies that "different regulations may call for different emphases in the analysis, depending on the nature and complexity of the regulatory issues and the sensitivity of the benefit and cost estimates to the key assumptions." On discounting, Circular A-4 recognizes that "special ethical considerations arise when comparing benefits and costs across generations," and Circular A-4 acknowledges that analyses may appropriately "discount future costs and consumption benefits…at a lower rate than for intragenerational analysis." In the 2015 Response to Comments on the Social Cost of Carbon for Regulatory Impact Analysis, OMB, EPA, and the other IWG members recognized that "Circular A-4 is a living document" and "the use of 7 percent is not considered appropriate for intergenerational discounting. There is wide support for this view in the academic literature, and it is recognized in Circular A-4 itself." Thus, EPA concludes that a 7 percent discount rate is not appropriate to apply to value the social cost of greenhouse gases in the analysis presented in this proposal. In this analysis, to calculate the present and annualized values of climate benefits, EPA uses the same discount rate as the rate used to discount the value of damages from future GHG emissions, for internal consistency. That approach to discounting follows the same approach that the February 2021 SC-GHG TSD recommends "to ensure internal consistency—i.e., future damages from climate change using the SC-GHG at 2.5 percent should be discounted to the base year of the analysis using the same 2.5 percent rate." EPA has also consulted the National

Academies' 2017 recommendations on how SC-GHG estimates can "be combined in RIAs with other cost and benefits estimates that may use different discount rates." The National Academies reviewed "several options," including "presenting all discount rate combinations of other costs and benefits with [SC-GHG] estimates."

While the IWG works to assess how best to incorporate the latest, peer reviewed science to develop an updated set of SC-GHG estimates, it recommended the interim estimates to be the most recent estimates developed by the IWG prior to the group being disbanded in 2017. The estimates rely on the same models and harmonized inputs and are calculated using a range of discount rates. As explained in the February 2021 SC-GHG TSD, the IWG has concluded that it is appropriate for agencies to revert to the same set of four values drawn from the SC-GHG distributions based on three discount rates as were used in regulatory analyses between 2010 and 2016 and subject to public comment. For each discount rate, the IWG combined the distributions across models and socioeconomic emissions scenarios (applying equal weight to each) and then selected a set of four values for use in agency analyses: an average value resulting from the model runs for each of three discount rates (2.5 percent, 3 percent, and 5 percent), plus a fourth value, selected as the 95th percentile of estimates based on a 3 percent discount rate. The fourth value was included to represent the extensive evidence in the scientific and economic literature of the potential for lower-probability, higher-impact outcomes from climate change, which would be particularly harmful to society and thus relevant to the public and policymakers. Absent formal inclusion of risk aversion in the modeling, considering values above the mean in a right skewed distribution with long tails acknowledges society's preference for avoiding risk when high consequence outcomes are possible. As explained in the February 2021 SC-GHG TSD, this update reflects the immediate need to have an operational SC-GHG that was developed using a transparent process, peer-reviewed methodologies, and the science available at the time of that process. Those estimates were subject to public comment in the context of dozens of proposed rulemakings as well as in a dedicated public comment period in 2013.

Table 4-1 summarizes the interim SC-CO_2 estimates for the years 2028–2042. These estimates are reported in 2020 dollars in the IWG's 2021 SC-GHG TSD but are otherwise identical to those presented in the IWG's 2016 TSD (IWG, 2016b) . For purposes of capturing uncertainty around the SC-CO_2 estimates in analyses, the February 2021 SC-GHG TSD emphasizes the importance of considering all four of the SC-CO_2 values. The SC-CO_2 increases over time within the models (i.e., the societal harm from one metric ton emitted in 2030 is higher than the harm caused by one metric ton emitted in 2025) because future emissions produce larger incremental damages as physical and economic systems become more stressed in response to greater climatic change, and because GDP is growing over time and many damage categories are modeled as proportional to GDP.

Table 4-1 Interim Social Cost of Carbon Values, 2028 to 2042 (2019 dollars per metric ton CO_2)

	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

Note: The 2028 to 2042 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.

There are a number of limitations and uncertainties associated with the SC-CO_2 estimates presented in Table 4-1. Some uncertainties are captured within the analysis, while other areas of uncertainty have not yet been quantified in a way that can be modeled. Figure 4-1 presents the quantified sources of uncertainty in the form of frequency distributions for the SC-CO_2 estimates for emissions in 2030 (in 2020$). The distribution of the SC-CO_2 estimate reflects uncertainty in key model parameters such as the equilibrium climate sensitivity, as well as uncertainty in other parameters set by the original model developers. To highlight the difference between the impact of the discount rate and other quantified sources of uncertainty, the bars below the frequency distributions provide a symmetric representation of quantified variability in the SC-CO_2

estimates for each discount rate. As illustrated by the figure, the assumed discount rate plays a critical role in the ultimate estimate of the SC-CO_2. This is because CO_2 emissions today continue to impact society far out into the future, so with a higher discount rate, costs that accrue to future generations are weighted less, resulting in a lower estimate. As discussed in the February 2021 SC-GHG TSD, there are other sources of uncertainty that have not yet been quantified and are thus not reflected in these estimates.

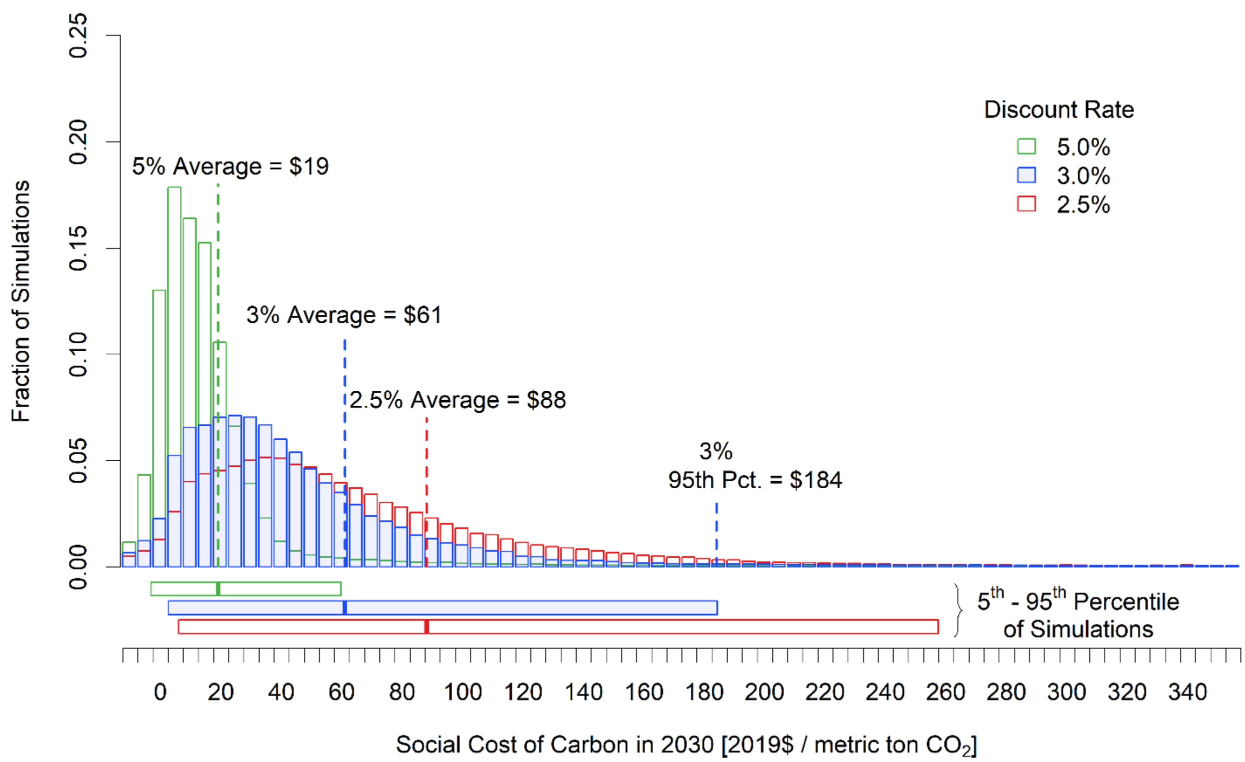

Figure 4-1 Frequency Distribution of SC-CO_2 Estimates for 2030[106]

The interim SC-GHG estimates presented in Table 4-1 have a number of other limitations. First, the current scientific and economic understanding of discounting approaches suggests discount rates appropriate for intergenerational analysis in the context of climate change are likely to be less than 3 percent, near 2 percent or lower (IWG, 2021). Second, the IAMs used to produce these interim estimates do not include all of the important physical, ecological, and

[106] Although the distributions and numbers are based on the full set of model results (150,000 estimates for each discount rate and gas), for display purposes the horizontal axis is truncated with 0.39 to 0.83 percent of the estimates falling below the lowest bin displayed and 0.26 to 3.39 percent of the estimates falling above the highest bin displayed, depending on the discount rate and GHG.

economic impacts of climate change recognized in the climate change literature and the science underlying their "damage functions" – i.e., the core parts of the IAMs that map global mean temperature changes and other physical impacts of climate change into economic (both market and nonmarket) damages – lags behind the most recent research. For example, limitations include the incomplete treatment of catastrophic and non-catastrophic impacts in the integrated assessment models, their incomplete treatment of adaptation and technological change, the incomplete way in which inter-regional and intersectoral linkages are modeled, uncertainty in the extrapolation of damages to high temperatures, and inadequate representation of the relationship between the discount rate and uncertainty in economic growth over long time horizons. Likewise, the socioeconomic and emissions scenarios used as inputs to the models do not reflect new information from the last decade of scenario generation or the full range of projections.

The modeling limitations do not all work in the same direction in terms of their influence on the SC-GHG estimates. However, as discussed in the February 2021 SC-GHG TSD, the IWG has recommended that, taken together, the limitations suggest that the SC-GHG estimates used in these proposed rules likely underestimate the damages from GHG emissions. EPA concurs that the values used in this rulemaking conservatively underestimate the rule's climate benefits. In particular, the Intergovernmental Panel on Climate Change (IPCC) Fourth Assessment Report, which was the most current IPCC assessment available at the time when the IWG decision over the ECS input was made, concluded that SC-CO_2 estimates "very likely…underestimate the damage costs" due to omitted impacts (IPCC, 2007). Since then, the peer-reviewed literature has continued to support this conclusion, as noted in the IPCC's Fifth Assessment report and other recent scientific assessments (IPCC, 2014, 2018, 2019a, 2019b; National Academies, 2016; National Academy of Sciences, 2019; USGCRP, 2016, 2018).

These assessments confirm and strengthen the science, updating projections of future climate change and documenting and attributing ongoing changes. For example, sea level rise projections from the IPCC's Fourth Assessment report ranged from 18 to 59 centimeters by the 2090s relative to 1980-1999, while excluding any dynamic changes in ice sheets due to the limited understanding of those processes at the time. A decade later, the Fourth National Climate Assessment projected a substantially larger sea level rise of 30 to 130 centimeters by the end of the century relative to 2000, while not ruling out even more extreme outcomes (USGCRP, 2018). EPA has reviewed and considered the limitations of the models used to estimate the interim SC-

GHG estimates and concurs with the February 2021 SC-GHG TSD's assessment that, taken together, the limitations suggest that the interim SC-GHG estimates likely underestimate the damages from GHG emissions.

The February 2021 SC-GHG TSD briefly previews some of the recent advances in the scientific and economic literature that the IWG is actively following and that could provide guidance on, or methodologies for, addressing some of the limitations with the interim SC-GHG estimates. The IWG is currently working on a comprehensive update of the SC-GHG estimates taking into consideration recommendations from the National Academies of Sciences, Engineering and Medicine, recent scientific literature, public comments received on the February 2021 SC-GHG TSD and other input from experts and diverse stakeholder groups (National Academies, 2017). While that process continues EPA is continuously reviewing developments in the scientific literature on the SC-GHG, including more robust methodologies for estimating damages from emissions, and looking for opportunities to further improve SC-GHG estimation going forward. Most recently, EPA presented a draft set of updated SC-GHG estimates within a sensitivity analysis in the regulatory impact analysis of EPA's November 2022 supplemental proposal for oil and gas standards that that aims to incorporate recent advances in the climate science and economics literature. Specifically, the draft updated methodology incorporates new literature and research consistent with the National Academies near-term recommendations on socioeconomic and emissions inputs, climate modeling components, discounting approaches, and treatment of uncertainty, and an enhanced representation of how physical impacts of climate change translate to economic damages in the modeling framework based on the best and readily adaptable damage functions available in the peer reviewed literature. EPA solicited public comment on the sensitivity analysis and the accompanying draft technical report, which explains the methodology underlying the new set of estimates, in the docket for the proposed oil and natural gas rule. EPA is also conducting an external peer review of this technical report. More information about this process and public comment opportunities is available on EPA's website.[107] The agency is in the process of reviewing public comments on the updated estimates within the oil and natural gas rulemaking docket as well as the recommendations of the external peer reviewers. EPA remains committed to using the best available science in its analyses. Thus,

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

if EPA's updated SC-GHG methodology is finalized before these rules are finalized, EPA intends to present monetized climate benefits using the updated SC-GHG estimates in the final RIA.

Table 4-3 through Table 4-5 show the estimated monetary value of the estimated changes in CO_2 emissions expected to occur over 2028 through 2042 for the illustrative scenarios. EPA estimated the dollar value of the GHG-related effects for each analysis year between 2028 and 2042 by applying the SC-GHG estimates presented in Table 4-1 to the estimated changes in GHG emissions in the corresponding year as shown in Table 4-2. EPA then calculated the present value (PV) and equivalent annualized value (EAV) of benefits from the perspective of 2024 by discounting each year-specific value to the year 2024 using the same discount rate used to calculate the SC-GHG.[108]

[108] According to OMB's Circular A-4 (OMB, 2003), an "analysis should focus on benefits and costs that accrue to citizens and residents of the United States", and international effects should be reported, but separately. Circular A-4 also reminds analysts that "[d]ifferent regulations may call for different emphases in the analysis, depending on the nature and complexity of the regulatory issues." To correctly assess the total climate damages to U.S. citizens and residents, an analysis should account for all the ways climate impacts affect the welfare of U.S. citizens and residents, including how U.S. GHG mitigation activities affect mitigation activities by other countries, and spillover effects from climate action elsewhere. The SC-GHG estimates used in regulatory analysis under revoked EO 13783 were a limited approximation of some of the U.S. specific climate damages from GHG emissions. These estimates range from $8 per metric ton CO_2 for emissions occurring in 2024 to $10 per metric ton CO_2 for emissions occurring in 2042. Applying the same estimates (based on a 3 percent discount rate) to the GHG emissions reduction expected under this proposed rule would yield benefits from climate impacts within U.S borders of $81 million in 2028, increasing to $239 million in 2042 for CO_2. However, as discussed at length in the IWG's February 2021 SC-GHG TSD, these estimates are an underestimate of the benefits of GHG mitigation accruing to U.S. citizens and residents, as well as being subject to a considerable degree of uncertainty due to the manner in which they are derived. In particular, as discussed in this analysis, EPA concurs with the assessment in the February 2021 SC-GHG TSD that the estimates developed under revoked E.O. 13783 did not capture significant regional interactions, spillovers, and other effects and so are incomplete underestimates. As the U.S. Government Accountability Office (GAO) concluded in a June 2020 report examining the SC-GHG estimates developed under E.O. 13783, the models "were not premised or calibrated to provide estimates of the social cost of carbon based on domestic damages" p.29 (U.S. GAO, 2020). Further, the report noted that the National Academies found that country-specific social costs of carbon estimates were "limited by existing methodologies, which focus primarily on global estimates and do not model all relevant interactions among regions" p.26 (U.S. GAO, 2020). It is also important to note that the SC-GHG estimates developed under E.O. 13783 were never peer reviewed, and when their use in a specific regulatory action was challenged, the U.S. District Court for the Northern District of California determined that use of those values had been "soundly rejected by economists as improper and unsupported by science," and that the values themselves omitted key damages to U.S. citizens and residents including to supply chains, U.S. assets and companies, and geopolitical security. The Court found that by omitting such impacts, those estimates "fail[ed] to consider…important aspect[s] of the problem" and departed from the "best science available" as reflected in the global estimates. California v. Bernhardt, 472 F. Supp. 3d 573, 613-14 (N.D. Cal. 2020). EPA continues to center attention in this analysis on the global measures of the SC-GHG as the appropriate estimates given the flaws in the U.S. specific estimates, and as necessary for all countries to use to achieve an efficient allocation of resources for emissions reduction on a global basis, and so benefit the U.S. and its citizens.

Table 4-2 Annual CO_2 Emissions Reductions (million metric tons) for the Illustrative Scenarios from 2028 through 2042

	Million Metric Tons of CO_2		
Emissions Year	**Proposal Scenario**	**Less Stringent Scenario**	**More Stringent Scenario**
2028	10.1	8.7	0.5
2029	89.2	82.6	106.7
2030	89.2	82.6	106.7
2031	89.2	82.6	106.7
2032	36.7	35.2	41.8
2033	36.7	35.2	41.8
2034	36.7	35.2	41.8
2035	36.7	35.2	41.8
2036	36.7	35.2	41.8
2037	36.7	35.2	41.8
2038	23.7	22.0	22.8
2039	23.7	22.0	22.8
2040	23.7	22.0	22.8
2041	23.7	22.0	22.8
2042	23.7	22.0	22.8
Total	616.8	577.9	685.3

Table 4-3 Benefits of Reduced CO_2 Emissions from the Illustrative Proposal Scenario, 2028 to 2042 (millions of 2019 dollars)[a]

	SC-CO_2 Discount Rate and Statistic (millions 2019 dollars)			
Emissions Year	**5% Average**	**3% Average**	**2.5% Average**	**3% 95th Percentile**
2028	$180	$600	$870	$1,800
2029	$1,700	$5,400	$7,800	$16,000
2030	$1,700	$5,400	$7,900	$16,000
2031	$1,800	$5,500	$8,000	$17,000
2032	$750	$2,300	$3,300	$7,100
2033	$770	$2,400	$3,400	$7,200
2034	$790	$2,400	$3,400	$7,300
2035	$810	$2,500	$3,500	$7,500
2036	$830	$2,500	$3,500	$7,600
2037	$850	$2,500	$3,600	$7,800
2038	$560	$1,700	$2,400	$5,100
2039	$580	$1,700	$2,400	$5,200
2040	$590	$1,700	$2,400	$5,300
2041	$610	$1,700	$2,400	$5,300
2042	$620	$1,800	$2,500	$5,400
PV	**$8,200**	**$30,000**	**$45,000**	**$92,000**
EAV	**$680**	**$2,100**	**$3,000**	**$6,400**

[a] Climate benefits are based on changes (reductions) in CO_2 emissions and are calculated using four different estimates of the SC-CO_2 (model average at 2.5 percent, 3 percent, and 5 percent discount rates; and 95th percentile at 3 percent discount rate). The IWG emphasized the importance and value of considering the benefits calculated using all four estimates. As discussed in the Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990 (IWG, 2021), a consideration of climate benefits calculated using discount rates below 3 percent, including 2 percent and lower, is also warranted when discounting intergenerational impacts.

Table 4-4 Benefits of Reduced CO_2 Emissions from the Illustrative Less Stringent Scenario, 2028 to 2042 (millions of 2019 dollars)[b]

	SC-CO_2 Discount Rate and Statistic (millions 2019 dollars)			
Emissions Year	**5% Average**	**3% Average**	**2.5% Average**	**3% 95th Percentile**
2028	$160	$510	$750	$1,500
2029	$1,500	$5,000	$7,200	$15,000
2030	$1,600	$5,000	$7,300	$15,000
2031	$1,600	$5,100	$7,400	$16,000
2032	$710	$2,200	$3,200	$6,800
2033	$740	$2,300	$3,300	$6,900
2034	$760	$2,300	$3,300	$7,000
2035	$780	$2,400	$3,400	$7,200
2036	$800	$2,400	$3,400	$7,300
2037	$820	$2,400	$3,400	$7,400
2038	$520	$1,500	$2,200	$4,700
2039	$540	$1,600	$2,200	$4,800
2040	$550	$1,600	$2,200	$4,900
2041	$560	$1,600	$2,300	$5,000
2042	$580	$1,600	$2,300	$5,000
PV	**$7,700**	**$28,000**	**$43,000**	**$86,000**
EAV	**$640**	**$2,000**	**$2,800**	**$6,000**

[b] Climate benefits are based on changes (reductions) in CO_2 emissions and are calculated using four different estimates of the SC-CO_2 (model average at 2.5 percent, 3 percent, and 5 percent discount rates; and 95th percentile at 3 percent discount rate). The IWG emphasized the importance and value of considering the benefits calculated using all four estimates. As discussed in the Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990 (IWG, 2021), a consideration of climate benefits calculated using discount rates below 3 percent, including 2 percent and lower, is also warranted when discounting intergenerational impacts.

Table 4-5 Benefits of Reduced CO_2 Emissions from the Illustrative More Stringent Scenario, 2028 to 2042 (millions of 2019 dollars)[c]

	SC-CO_2 Discount Rate and Statistic (millions 2019 dollars)			
Emissions Year	**5% Average**	**3% Average**	**2.5% Average**	**3% 95th Percentile**
2028	$9.0	$29	$43	$88
2029	$2,000	$6,400	$9,300	$19,000
2030	$2,000	$6,500	$9,400	$20,000
2031	$2,100	$6,600	$9,600	$20,000
2032	$850	$2,600	$3,800	$8,000
2033	$870	$2,700	$3,900	$8,200
2034	$900	$2,700	$3,900	$8,300
2035	$920	$2,800	$4,000	$8,500
2036	$940	$2,800	$4,000	$8,700
2037	$970	$2,900	$4,100	$8,800
2038	$540	$1,600	$2,300	$4,900
2039	$550	$1,600	$2,300	$5,000
2040	$570	$1,600	$2,300	$5,100
2041	$580	$1,700	$2,400	$5,100
2042	$600	$1,700	$2,400	$5,200
PV	**$9,100**	**$34,000**	**$51,000**	**$100,000**
EAV	**$760**	**$2,400**	**$3,400**	**$7,100**

[c] Climate benefits are based on changes (reductions) in CO_2 emissions and are calculated using four different estimates of the SC-CO_2 (model average at 2.5 percent, 3 percent, and 5 percent discount rates; and 95th percentile at 3 percent discount rate). The IWG emphasized the importance and value of considering the benefits calculated using all four estimates. As discussed in the Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990 (IWG, 2021), a consideration of climate benefits calculated using discount rates below 3 percent, including 2 percent and lower, is also warranted when discounting intergenerational 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.[109] We conduct this analysis by adapting primary research—specifically, air pollution epidemiology studies and economic value studies—from similar contexts. This approach is sometimes referred to as "benefits transfer." Below we describe the procedure we follow for: (1) 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, the proposed rules would affect the distribution of ozone and $PM_{2.5}$ concentrations in much of the U.S. This RIA estimates avoided ozone- and $PM_{2.5}$-related health impacts that are distinct from those reported in the RIAs for both ozone and PM NAAQS (U.S. EPA, 2012, 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 and 2040.

4.3.1 Air Quality Modeling Methodology

The proposed 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 $PM_{2.5}$

[109] This RIA also reports the change in the sum of the risk, or the change in the total incidence, of a health outcome across the population. If the benefit per unit of risk is invariant across individuals, the total expected change in the incidence of the health outcome across the population can be multiplied by the benefit per unit of risk to estimate the social benefit of the total expected change in the incidence of the health outcome.

concentrations that may occur as a result of the three illustrative scenarios for the proposed rules relative to the baseline.

As described in the Air Quality Modeling Appendix (Appendix A), 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. While 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 proposed 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 which, in turn, was used to quantify the benefits from this proposed rule.

The basic methodology for determining air quality changes is the same as that used in the RIAs from multiple previous rules (EPA, 2020; U.S. EPA, 2019b, 2020a, 2021, 2022c). The Air Quality Modeling Appendix (Appendix A) 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 appendix also provides figures showing the geographical distribution of air quality changes in the illustrative scenarios relative to the baseline.

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, 2020c), 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[110].

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

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

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 4-6 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 4-22 below report other omitted health and environmental benefits expected from the emissions and effluent changes as a result of this proposal, such as health effects associated with NO_2 and SO_2, and any welfare effects such as acidification and nutrient enrichment.

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.[111] 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.[112] At the same time, WTP may be lower for those health outcomes for which causality has not been definitively established. This approach treats relationships with ISA causality determinations of "likely to be causal" as if they were known to be causal, and therefore benefits could be overestimated. Table 4-6 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.

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[111] 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.

[112] 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).

Table 4-6 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 5.2
	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, and 2040 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

$$y_{ij} = \Sigma a \; y_{ij}a$$

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

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, 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.[113]

The BenMAP-CE tool is pre-loaded with projected population from the Woods & Poole company; cause-specific and age-stratified death rates from the Centers for Disease Control and Prevention, projected to future years; recent-year baseline rates of hospital admissions, emergency department visits and other morbidity outcomes from the Healthcare Cost and Utilization Program and other sources; concentration-response parameters from the published epidemiologic literature cited in the Integrated Science Assessments for fine particles and ground-level ozone; and cost of illness or willingness to pay economic unit values for each endpoint.

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.

[113] 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.

4.3.5 Benefits Analysis Data Inputs

In Figure 4-2, we summarize the key data inputs to the health impact and economic valuation estimates, 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.

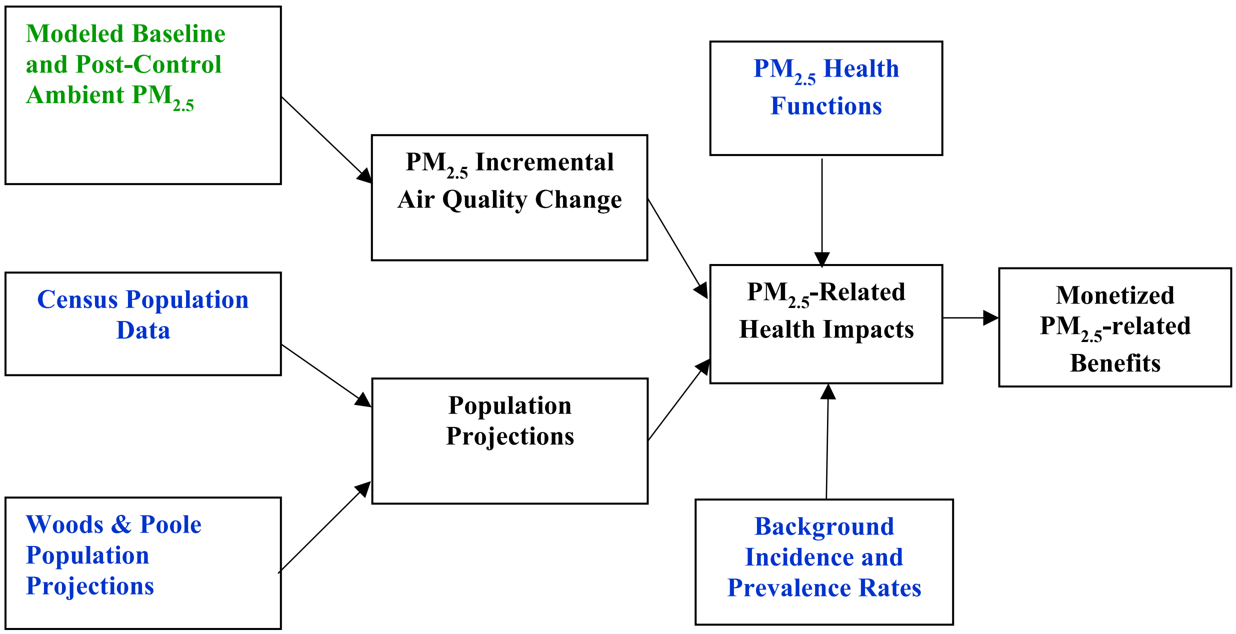

Figure 4-2 Data Inputs and Outputs for the BenMAP-CE Model

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., (EPA, 2020; U.S. EPA, 2019b, 2020a, 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 (NRC, 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" (NRC, 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)In 2008, the National Academies of Science (NRC, 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" (NRC, 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 (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, 2020c). Beginning with the RCU analysis we use two estimates of ozone-attributable respiratory deaths from short-term exposures are 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 May-September.(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, 2020c). Beginning with the RCU analysis we use two estimates of ozone-attributable respiratory deaths from short-term exposures are 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 May-September.

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.

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 other recent RIAs, 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 fine particle standard 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).

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 proposed 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.

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

4.3.9 Estimated Number and Economic Value of Health Benefits

Table 4-7 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 4-7 through Table 4-10 report the ozone-related health benefits for each scenario year, and Table 4-11 through Table 4-14 report the PM-related health benefits for each scenario 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 4-18 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 4-19 summarizes the monetized benefits for all illustrative scenarios and the four analysis years. We also report the stream of benefits from 2028 through 2042 for the proposal, more- and less- stringent alternatives, using the monetized sums of long-term ozone and $PM_{2.5}$ mortality and morbidity impacts (Table 4-15 through Table 4-19).[114] 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 2042 and estimates of baseline mortality incidence rates at five-year increments.

Table 4-15 through Table 4-18 include two estimates for each scenario. 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 based on Wu et al. (2020). These estimates should not be thought of as representing low and high bounds.

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

Table 4-7 Estimated Avoided Ozone-Related Premature Respiratory Mortalities and Illnesses for the Illustrative Scenarios for 2028 (95 percent confidence interval)[a]

		Proposal	Less Stringent	More Stringent
Avoided premature respiratory mortalities				
Long-term exposure	Turner et al. (2016)[b]	21 (14 to 27)	16 (11 to 20)	-38 (-26 to -49)
Short-term exposure	Katsouyanni et al. (2009)[b,c] and Zanobetti et al. (2008)[c] pooled	0.94 (0.38 to 1.5)	0.7 (0.28 to 1.1)	-1.7 (-2.7 to -0.69)
Morbidity effects				
Long-term exposure	Asthma onset[d]	180 (160 to 210)	150 (130 to 170)	-290 (-250 to -330)
	Allergic rhinitis symptoms[f]	1,000 (540 to 1,500)	830 (440 to 1,200)	-1,700 (-880 to -2,400)
Short-term exposure	Hospital admissions—respiratory[c]	2.3 (-0.61 to 5.2)	1.7 (-0.43 to 3.7)	-5 (1.3 to 11)
	ED visits—respiratory[e]	65 (18 to 140)	52 (14 to 110)	-82 (-170 to -23)
	Asthma symptoms	33,000 (-4,100 to 70,000)	27,000 (-3,300 to 56,000)	-54,000 (-110,000 to 6,700)
	Minor restricted-activity days[c,e]	16,000 (6,200 to 25,000)	12,000 (4,900 to 20,000)	-25,000 (-10,000 to -40,000)
	School absence days	12,000 (-1,700 to 25,000)	9,400 (-1,300 to 20,000)	-19,000 (2,700 to -40,000)

[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 in 2030 (95 percent confidence interval)[a]

		Proposal	Less Stringent	More Stringent
Avoided premature respiratory mortalities				
Long-term exposure	Turner et al. (2016)[b]	95 (66 to 120)	83 (58 to 110)	60 (41 to 77)
Short-term exposure	Katsouyanni et al. (2009)[b,c] and Zanobetti et al. (2008)[c] pooled	4.3 (1.7 to 6.8)	3.8 (1.5 to 5.9)	2.7 (1.1 to 4.3)
Morbidity effects				
Long-term exposure	Asthma onset[d]	560 (480 to 630)	480 (410 to 540)	320 (280 to 370)
	Allergic rhinitis symptoms[f]	3,300 (1,700 to 4,800)	2,800 (1,500 to 4,100)	1,900 (990 to 2,700)
Short-term exposure	Hospital admissions—respiratory[c]	11 (-3.0 to 25)	9.9 (-2.6 to 22)	6.9 (-1.8 to 15)
	ED visits—respiratory[e]	180 (49 to 370)	150 (42 to 320)	82 (23 to 170)
	Asthma symptoms	110,000 (-13,000 to 220,000)	91,000 (-11,000 to 190,000)	62,000 (-7,600 to 130,000)
	Minor restricted-activity days[c,e]	46,000 (18,000 to 72,000)	39,000 (16,000 to 62,000)	24,000 (9,400 to 37,000)
	School absence days	38,000 (-5,300 to 79,000)	32,000 (-4,500 to 67,000)	22,000 (-3,100 to 45,000)

[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 4-9 Estimated Avoided Ozone-Related Premature Respiratory Mortalities and Illnesses for the Illustrative Scenarios in 2035 (95 percent confidence interval)[a]

		Proposal	Less Stringent	More Stringent
Avoided premature respiratory mortalities				
Long-term exposure	Turner et al. (2016)[b]	26 (18 to 33)	18 (12 to 23)	23 (16 to 30)
Short-term exposure	Katsouyanni et al. (2009)[b,c] and Zanobetti et al. (2008)[c] pooled	1.2 (0.47 to 1.8)	0.79 (0.32 to 1.3)	1.1 (0.43 to 1.7)
Morbidity effects				
Long-term exposure	Asthma onset[d]	180 (150 to 200)	130 (110 to 150)	160 (130 to 180)
	Allergic rhinitis symptoms[f]	1,100 (550 to 1,500)	750 (400 to 1,100)	910 (480 to 1,300)
Short-term exposure	Hospital admissions—respiratory[c]	3.1 (-0.81 to 6.8)	2.0 (-0.52 to 4.5)	2.8 (-0.73 to 6.2)
	ED visits—respiratory[e]	63 (17 to 130)	45 (12 to 94)	55 (15 to 120)
	Asthma symptoms	33,000 (-4,100 to 69,000)	24,000 (-2,900 to 50,000)	29,000 (-3,600 to 60,000)
	Minor restricted-activity days[c,e]	16,000 (6,300 to 25,000)	11,000 (4,500 to 18,000)	14 ,000 (5,400 to 21,000)
	School absence days	12,000 (-1,700 to 25,000)	8,600 (-1,200 to 18,000)	10,000 (-1,500 to 22,000)

[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 Ozone-Related Premature Respiratory Mortalities and Illnesses for the Illustrative Scenarios in 2040 (95 percent confidence interval)[a,b]

		Proposal	Less Stringent	More Stringent
Avoided premature respiratory mortalities				
Long-term exposure	Turner et al. (2016)[b]	0.26 (0.18 to 0.33)	-7.0 (-4.8 to -9.1)	1.8 (1.2 to 2.3)
Short-term exposure	Katsouyanni et al. (2009)[b,c] and Zanobetti et al. (2008)[c] pooled	0.012 (0.0049 to 0.019)	-0.32 (-0.50 to -0.13)	0.081 (0.033 to 0.13)
Morbidity effects				
Long-term exposure	Asthma onset[d]	21 (18 to 24)	-26 (-22 to -30)	26 (22 to 29)
	Allergic rhinitis symptoms[f]	120 (64 to 180)	-160 (-82 to -230)	150 (78 to 220)
Short-term exposure	Hospital admissions—respiratory[c]	-0.021 (0.0054 to -0.046)	-1.0 (0.26 to -2.2)	0.18 (-0.047 to 0.39)
	ED visits—respiratory[e]	8.3 (2.3 to 17)	-8.0 (-17 to -2.2)	8.4 (2.3 to 18)
	Asthma symptoms	3,900 (-480 to 8,100)	-4,900 (-10,000 to 600)	4,800 (-590 to 10,000)
	Minor restricted-activity days[c,e]	1,400 (550 to 2,200)	-2,800 (-1,100 to -4,400)	1,600 (640 to 2,500)
	School absence days	1,400 (-190 to 2,900)	-1,800 (250 to -3,800)	1,700 (-240 to 3,600)

[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 4-11 Estimated Avoided PM-Related Premature Respiratory Mortalities and Illnesses for the Illustrative Scenarios in 2028 (95 percent confidence interval)

Avoided Mortality	Proposal	Less Stringent	More Stringent
(Pope et al., 2019) (adult mortality ages 18-99 years)	130 (92 to 160)	93 (66 to 120)	0.86 (0.62 to 1.1)
(Wu et al., 2020) (adult mortality ages 65-99 years)	61 (53 to 68)	44 (38 to 49)	0.090 (0.080 to 0.10)
(Woodruff et al., 2008) (infant mortality)	0.16 (-0.10 to 0.42)	0.12 (-0.075 to 0.31)	0.012 (-0.0073 to 0.030)
Avoided Morbidity			
Hospital admissions—cardiovascular (age > 18)	8.9 (6.5 to 11)	6.4 (4.6 to 8.1)	-0.068 (-0.049 to -0.086)
Hospital admissions—respiratory	1.3 (0.049 to 2.5)	0.91 (0.034 to 1.7)	-0.036 (-0.0013 to -0.068)
ED visits--cardiovascular	19 (-7.3 to 44)	14 (-5.2 to 32)	0.35 (-0.13 to 0.81)
ED visits—respiratory	40 (7.9 to 84)	29 (5.7 to 61)	1.9 (0.38 to 4.0)
Acute Myocardial Infarction	2.0 (1.2 to 2.8)	1.4 (0.82 to 2.0)	-0.062 (-0.036 to -0.087)
Cardiac arrest	0.99 (-0.40 to 2.2)	0.72 (-0.29 to 1.6)	0.033 (-0.013 to 0.074)
Hospital admissions--Alzheimer’s Disease	28 (21 to 35)	19 (14 to 24)	-2.4 (-1.8 to -3.0)
Hospital admissions--Parkinson’s Disease	3.9 (2.0 to 5.8)	2.7 (1.4 to 4.0)	-0.15 (-0.078 to -0.23)
Stroke	3.9 (1.0 to 6.7)	2.8 (0.73 to 4.8)	0.12 (0.032 to 0.21)
Lung cancer	4.4 (1.3 to 7.4)	3.2 (0.98 to 5.4)	0.13 (0.039 to 0.21)
Hay Fever/Rhinitis	1,000 (250 to 1,800)	760 (180 to 1,300)	61 (15 to 110)
Asthma Onset	160 (150 to 170)	120 (110 to 120)	11 (10 to 11)
Asthma symptoms – Albuterol use	22,000 (-11,000 to 53,000)	16,000 (-7,800 to 39,000)	1,300 (-620 to 3,100)
Lost work days	7,700 (6,500 to 8,900)	5,700 (4,800 to 6,600)	340 (290 to 390)
Minor restricted-activity days[d,f]	45,000 (37,000 to 54,000)	33,000 (27,000 to 40,000)	2,000 (1,600 to 2,300)

Note: Values rounded to two significant figures.

Table 4-12 Estimated Avoided PM-Related Premature Respiratory Mortalities and Illnesses for the Illustrative Scenarios in 2030 (95 percent confidence interval)

Avoided Mortality	Proposal	Less Stringent	More Stringent
(Pope et al., 2019) (adult mortality ages 18-99 years)	1,200 (880 to 1,600)	1,100 (790 to 1,400)	1,200 (860 to 1,500)
(Wu et al., 2020) (adult mortality ages 65-99 years)	590 (520 to 650)	530 (470 to 590)	580 (510 to 640)
(Woodruff et al., 2008) (infant mortality)	1.4 (-0.89 to 3.6)	1.3 (-0.81 to 3.3)	1.4 (-0.88 to 3.6)
Avoided Morbidity			
Hospital admissions—cardiovascular (age > 18)	85 (62 to 110)	77 (56 to 98)	84 (61 to 110)
Hospital admissions—respiratory	14 (0.52 to 26)	12 (0.47 to 24)	13 (0.51 to 26)
ED visits--cardiovascular	180 (-68 to 410)	160 (-62 to 370)	170 (-67 to 400)
ED visits—respiratory	340 (67 to 710)	310 (61 to 650)	330 (66 to 700)
Acute Myocardial Infarction	20 (12 to 28)	18 (10 to 25)	20 (11 to 28)
Cardiac arrest	8.9 (-3.6 to 20)	8.1 (-3.3 to 18)	8.7 (-3.5 to 20)
Hospital admissions--Alzheimer's Disease	320 (240 to 400)	290 (220 to 360)	320 (240 to 400)
Hospital admissions--Parkinson's Disease	39 (20 to 57)	35 (18 to 52)	38 (19 to 56)
Stroke	36 (9.3 to 62)	33 (8.5 to 56)	35 (9.1 to 60)
Lung cancer	41 (12 to 68)	37 (11 to 61)	40 (12 to 66)
Hay Fever/Rhinitis	8,900 (2,100 to 15,000)	8,100 (2,000 to 14,000)	8,600 (2,100 to 15,000)
Asthma Onset	1,400 (1,300 to 1,400)	1,200 (1,200 to 1,300)	1,300 (1,300 to 1,400)
Asthma symptoms – Albuterol use	190,000 (-92,000 to 460,000)	170,000 (-84,000 to 420,000)	180,000 (-89,000 to 450,000)
Lost work days	66,000 (55,000 to 76,000)	60,000 (50,000 to 69,000)	63,000 (53,000 to 73,000)
Minor restricted-activity days[d,f]	390,000 (310,000 to 460,000)	350,000 (290,000 to 420,000)	370,000 (300,000 to 440,000)

Note: Values rounded to two significant figures.

Table 4-13 Estimated Avoided PM-Related Premature Respiratory Mortalities and Illnesses for the Illustrative Scenarios in 2035 (95 percent confidence interval)

Avoided Mortality	**Proposal**	**Less Stringent**	**More Stringent**
(Pope et al., 2019) (adult mortality ages 18-99 years)	400 (280 to 510)	340 (240 to 430)	390 (280 to 500)
(Wu et al., 2020) (adult mortality ages 65-99 years)	190 (170 to 220)	170 (150 to 190)	190 (170 to 220)
(Woodruff et al., 2008) (infant mortality)	0.42 (-0.27 to 1.1)	0.36 (-0.23 to 0.94)	0.42 (-0.27 to 1.1)
Avoided Morbidity			
Hospital admissions—cardiovascular (age > 18)	29 (21 to 36)	24 (18 to 31)	28 (20 to 36)
Hospital admissions—respiratory	4.5 (0.17 to 8.6)	3.8 (0.14 to 7.3)	4.4 (0.17 to 8.5)
ED visits--cardiovascular	59 (-23 to 140)	51 (-20 to 120)	59 (-23 to 140)
ED visits—respiratory	120 (23 to 240)	100 (20 to 210)	120 (23 to 240)
Acute Myocardial Infarction	6.3 (3.7 to 8.9)	5.3 (3.1 to 7.5)	6.3 (3.7 to 8.8)
Cardiac arrest	2.9 (-1.2 to 6.5)	2.5 (-1.0 to 5.6)	2.8 (-1.2 to 6.4)
Hospital admissions--Alzheimer's Disease	99 (74 to 120)	83 (62 to 100)	100 (74 to 120)
Hospital admissions--Parkinson's Disease	12 (6.3 to 18)	11 (5.4 to 16)	12 (6.2 to 18)
Stroke	12 (3.1 to 20)	10 (2.6 to 17)	12 (3.0 to 20)
Lung cancer	14 (4.2 to 23)	12 (3.6 to 20)	14 (4.1 to 23)
Hay Fever/Rhinitis	2,800 (680 to 4,900)	2,400 (590 to 4,200)	2,700 (660 to 4,800)
Asthma Onset	430 (410 to 450)	370 (360 to 390)	420 (400 to 440)
Asthma symptoms – Albuterol use	59,000 (-29,000 to 140,000)	51,000 (-25,000 to 120,000)	57,000 (-28,000 to 140,000)
Lost work days	21,000 (18,000 to 24,000)	18,000 (15,000 to 21,000)	20,000 (17,000 to 23,000)
Minor restricted-activity days[d,f]	120,000 (99,000 to 140,000)	110,000 (86,000 to 120,000)	120,000 (97,000 to 140,000)

Note: Values rounded to two significant figures.

Table 4-14 Estimated Avoided PM-Related Premature Respiratory Mortalities and Illnesses for the Illustrative Scenarios in 2040 (95 percent confidence interval)

Avoided Mortality	**Proposal**	**Less Stringent**	**More Stringent**
(Pope et al., 2019) (adult mortality ages 18-99 years)	320 (230 to 400)	240 (170 to 300)	330 (240 to 430)
(Wu et al., 2020) (adult mortality ages 65-99 years)	160 (140 to 180)	120 (100 to 130)	170 (150 to 190)
(Woodruff et al., 2008) (infant mortality)	0.31 (-0.20 to 0.80)	0.24 (-0.15 to 0.62)	0.33 (-0.21 to 0.84)
Avoided Morbidity			
Hospital admissions—cardiovascular (age > 18)	24 (17 to 30)	17 (12 to 22)	25 (18 to 32)
Hospital admissions—respiratory	3.7 (0.14 to 7.1)	2.7 (0.10 to 5.1)	3.9 (0.15 to 7.5)
ED visits--cardiovascular	49 (-19 to 110)	36 (-14 to 85)	51 (-20 to 120)
ED visits—respiratory	95 (19 to 200)	72 (14 to 150)	99 (19 to 210)
Acute Myocardial Infarction	5.1 (3.0 to 7.2)	3.7 (2.1 to 5.2)	5.5 (3.2 to 7.7)
Cardiac arrest	2.3 (-0.95 to 5.3)	1.7 (-0.70 to 3.9)	2.5 (-1.0 to 5.6)
Hospital admissions--Alzheimer's Disease	24 (17 to 30)	17 (12 to 22)	25 (18 to 32)
Hospital admissions--Parkinson's Disease	9.5 (4.8 to 14)	7.1 (3.6 to 11)	10 (5.1 to 15)
Stroke	9.5 (2.5 to 16)	7.0 (1.8 to 12)	10 (2.6 to 17)
Lung cancer	12 (3.5 to 19)	8.6 (2.6 to 14)	12 (3.7 to 20)
Hay Fever/Rhinitis	2,200 (540 to 3,900)	1,700 (410 to 2,900)	2,400 (570 to 4,100)
Asthma Onset	340 (330 to 360)	260 (250 to 270)	360 (350 to 380)
Asthma symptoms – Albuterol use	47,000 (-23,000 to 110,000)	35,000 (-17,000 to 85,000)	50,000 (-24,000 to 120,000)
Lost work days	17,000 (14,000 to 20,000)	13,000 (11,000 to 15,000)	18,000 (15,000 to 21,000)
Minor restricted-activity days[d,f]	100,000 (81,000 to 120,000)	75,000 (61,000 to 88,000)	110,000 (86,000 to 130,000)

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; millions of 2019 dollars)[a]

Disc. Rate	Pollutant	Ozone Benefits	PM Benefits	Ozone plus PM Benefits
3%	Proposal	\$32 (\$8.2 to \$66) *and* \$240 (\$27 to \$620)	\$650 (\$69 to \$1,700) *and* \$1,400 (\$130 to \$3,700)	\$680 (\$77 to \$1,800)[b] *and* \$1,600 (\$160 to \$4,300)[c]
	Less Stringent	\$25 (\$6.6 to \$51) *and* \$180 (\$21 to \$470)	\$470 (\$50 to \$1,200) *and* \$990 (\$96 to \$2,600)	\$490 (\$56 to \$1,300)[b] *and* \$1,200 (\$120 to \$3,100)[c]
	More Stringent	-\$430 (-\$1,100 to -\$47) *and* -\$53 (-\$110 to -\$13)	\$1.9 (\$0.61 to \$4) *and* \$10 (\$1.3 to \$26)	-\$420 (-\$1,100 to -\$21)[b] *and* -\$51 (-\$110 to -\$9.3)[c]
7%	Proposal	\$28 (\$5.3 to 62) *and* \$210 (\$22 to \$560)	\$590 (\$60 to \$1,500) *and* \$1,200 (\$120 to \$3,300)	\$610 (\$66 to \$1,600)[b] *and* \$1,400 (\$140 to \$3,900)[c]
	Less Stringent	\$22 (\$4.2 to \$48) *and* \$160 (\$17 to \$420)	\$420 (\$43 to \$1,100) *and* \$890 (\$85 to \$2,400)	\$440 (\$48 to \$1,200)[b] *and* \$1,000 (\$100 to \$2,800)[c]
	More Stringent	-\$380 (-\$1,000 to -\$39) *and* -\$48 (-\$110 to -\$8.6)	\$1.6 (\$0.41 to \$3.5) *and* \$8.9 (\$1.1 to \$23)	-\$370 (-\$1,000 to -\$16)[b] *and* -\$46 (-\$110 to -\$5)[c]

[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.

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; millions of 2019 dollars)[a]

Disc. Rate	Pollutant	Ozone Benefits	PM Benefits	Ozone plus PM Benefits
3%	Proposal	$120 ($26 to $250) *and* $1,100 ($110 to $2,800)	$6,300 ($660 to $17,000) *and* $13,000 ($1,300 to $35,000)	$6,500 ($690 to $17,000)[b] *and* $14,000 ($1,400 to $38,000)[c]
	Less Stringent	$100 ($23 to $220) *and* $930 ($98 to $2,500)	$5,800 ($600 to $15,000) *and* $12,000 ($1,100 to $32,000)	$5,900 ($620 to $15,000)[b] *and* $13,000 ($1,200 to $34,000)[c]
	More Stringent	$69 ($15 to $150) *and* $670 ($70 to $1,800)	$6,300 ($650 to $16,000) *and* $13,000 ($1,200 to $35,000)	$6,300 ($670 to $17,000)[b] *and* $14,000 ($1,300 to $36,000)[c]
7%	Proposal	$100 ($17 to 240) *and* $960 ($94 to $2,500)	$5,700 ($580 to $15,000) *and* $12,000 ($1,100 to $31,000)	$5,800 ($600 to $15,000)[b] *and* $13,000 ($1,200 to $34,000)[c]
	Less Stringent	$91 ($15 to $210) *and* $840 ($83 to $2,200)	$5,200 ($530 to $14,000) *and* $11,000 ($1,000 to $29,000)	$5,300 ($540 to $14,000)[b] *and* $12,000 ($1,100 to $31,000)[c]
	More Stringent	$63 ($10 to $150) *and* $600 ($59 to $1,600)	$5,600 ($570 to $15,000) *and* $12,000 ($1,100 to $32,000)	$5,700 ($580 to $15,000)[b] *and* $12,000 ($1,200 to $33,000)[c]

[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.

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; millions of 2019 dollars)[a]

Disc. Rate	Pollutant	Ozone Benefits	PM Benefits	Ozone plus PM Benefits
3%	Proposal	$35 ($8.3 to $75) *and* $300 ($32 to $790)	$2,200 ($220 to $5,700) *and* $4,400 ($420 to $12,000)	$2,200 ($230 to $5,700)[b] *and* $4,700 ($450 to $13,000)[c]
	Less Stringent	$24 ($5.9 to $52) *and* $210 ($22 to $540)	$1,800 ($190 to $4,800) *and* $3,700 ($360 to $10,000)	$1,900 ($200 to $4,900)[b] *and* $3,900 ($380 to $11,000)[c]
	More Stringent	$31 ($7.3 to $67) *and* $270 ($29 to $720)	$2,100 ($220 to $5,600) *and* $4,300 ($420 to $12,000)	$2,200 ($230 to $5,700)[b] *and* $4,600 ($450 to $12,000)[c]
7%	Proposal	$31 ($5.4 to 71) *and* $270 ($27 to $710)	$1,900 ($200 to $5,100) *and* $3,900 ($370 to $11,000)	$2,000 ($200 to $5,200)[b] *and* $4,200 ($400 to $11,000)[c]
	Less Stringent	$22 ($3.8 to $50) *and* $180 ($19 to $490)	$1,700 ($170 to $4,300) *and* $3,300 ($320 to $9,000)	$1,700 ($170 to $4,400)[b] *and* $3,500 ($340 to $9,500)[c]
	More Stringent	$28 ($4.8 to $64) *and* $240 ($24 to $650)	$1,900 ($190 to $5,100) *and* $3,900 ($370 to $10,000)	$2,000 ($200 to $5,100)[b] *and* $4,100 ($390 to $11,000)[c]

[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.

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; millions of 2019 dollars)[a]

Disc. Rate	Pollutant	Ozone Benefits	PM Benefits	Ozone plus PM Benefits
3%	Proposal	$2.5 ($0.85 to $4.4) *and* $5.3 ($1.1 to $12)	$1,800 ($190 to $4,700) *and* $3,600 ($340 to $9,600)	$1,800 ($190 to $4,700)[b] *and* $3,600 ($340 to $9,600)[c]
	Less Stringent	-$81 (-$220 to -$8) *and* -$7 (-$1.4 to -$16)	$1,300 ($140 to $3,500) *and* $2,700 ($260 to $7,100)	$1,300 ($120 to $3,500)[b] *and* $2.600 ($40 to $7,100)[c]
	More Stringent	$3.9 ($1.1 to $7.8) *and* $23 ($2.8 to $59)	$1,900 ($200 to $5,000) *and* $3,800 ($360 to $10,000)	$1,900 ($200 to $5,000)[b] *and* $3,800 ($370 to $10,000)[c]
7%	Proposal	$2.2 ($0.51 to 3.9) *and* $4.6 ($0.73 to $11)	$1,600 ($160 to $4,200) *and* $3,200 ($300 to $8,600)	$1,600 ($160 to $4,200)[b] *and* $3,200 ($310 to $8,600)[c]
	Less Stringent	-$6.5 (-$16 to -$0.95) *and* -$73 (-$190 to -$6.9)	$1,200 ($120 to $3,100) *and* $2,400 ($230 to $6,400)	$1,200 ($110 to $3,100)[b] *and* $2,300 ($33 to $6,400)[c]
	More Stringent	$3.5 ($0.68 to $72) *and* $20 ($2.2 to $53)	$1,700 ($170 to $4,500) *and* $3,400 ($320 to $9,100)	$1,700 ($170 to $4,500)[b] *and* $3,400 ($320 to $9,200)[c]

[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.

Table 4-19 Estimated Discounted Economic Value of Avoided Ozone and $PM_{2.5}$-Attributable Premature Mortality and Illness for the Illustrative Scenarios in 2028, 2030, 2035 and 2040 (95 percent confidence interval; millions of 2019 dollars)[a,b]

		3% Discount Rate			7% Discount Rate		
		Ozone Benefits	**PM Benefits**	**Ozone plus PM Benefits**	**Ozone Benefits**	**PM Benefits**	**Ozone plus PM Benefits**
2028	Proposal	$32 and $240	$650 and $1400	$680 and $1600	$28 and $210	$590 and $1,200	$610 and $1,400
	Less Stringent	$25 and $180	$470 and $990	$490 and $1200	$22 and $160	$420 and $890	$440 and $1,000
	More Stringent	-$430 and -$53	$1.9 and $10	-$420 and -$51	-$380 and -$48	$1.6 and $8.9	-$370 and -$46
2030	Proposal	$120 and $1,100	$6,300 and $13,000	$6,500 and $14,000	$100 and $960	$5,700 and $12,000	$5,800 and $13,000
	Less Stringent	$100 and $930	$5,800 and $12,000	$5,900 and $13,000	$91 and $840	$5,200 and $11,000	$5,300 and $12,000
	More Stringent	$69 and $670	$6,300 and $13,000	$6,300 and $14,000	$63 and $600	$5,600 and $12,000	$5,700 and $12,000
2035	Proposal	$35 and $300	$2,200 and $4,400	$2,200 and $4,700	$31 and $270	$1,900 and $3,900	$2,000 and $4,200
	Less Stringent	$24 and $210	$1,800 and $3,700	$1,900 and $3,900	$22 and $180	$1,700 and $3,300	$1,700 and $3,500
	More Stringent	$31 and $270	$2,100 and $4,300	$2,200 and $4,600	$28 and $240	$1,900 and $3,900	$2,000 and $4,100
2040	Proposal	$2.5 and $5.3	$1,800 and $3,600	$1,800 and $3,600	$2.2 and $4.6	$1,600 and $3200	$1,600 and $3,200
	Less Stringent	-$7 and -$81	$1,300 and $2,700	$1,300 and $2,600	-$6.5 and -$73	$1,200 and $2,400	$1,200 and $2,300
	More Stringent	$3.9 and $23	$1,900 and $3,800	$1,900 and $3,800	$3.5 and $20	$1,700 and $3,400	$1,700 and $3,400

[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 4-7 through 4-14.

Table 4-20 Stream of Human Health Benefits from 2028 through 2042: 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; millions of 2019 dollars)[a]

	Proposal	Less Stringent	More Stringent
2028*	$1,600	$1,200	($420)
2029	$14,000	$13,000	$13,000
2030*	$14,000	$13,000	$14,000
2031	$14,000	$13,000	$14,000
2032	$4,300	$3,600	$4,300
2033	$4,400	$3,700	$4,400
2034	$4,500	$3,800	$4,500
2035*	$4,700	$3,900	$4,600
2036	$4,800	$4,000	$4,700
2037	$4,900	$4,100	$4,500
2038	$3,400	$2,500	$3,600
2039	$3,500	$2,500	$3,700
2040*	$3,600	$2,600	$3,800
2041	$3,600	$2,600	$3,900
2042	$3,700	$2,700	$3,900
PV	**$68,000**	**$58,000**	**$65,000**
EAV	**$4,800**	**$4,100**	**$4,600**

*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.

Table 4-21 Stream of Human Health Benefits from 2028 through 2042: 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; millions of 2019 dollars)[a]

	Proposal	Less Stringent	More Stringent
2028*	$1,400	$1,000	($370)
2029	$12,000	$11,000	$12,000
2030*	$13,000	$12,000	$12,000
2031	$13,000	$12,000	$12,000
2032	$3,900	$3,300	$3,800
2033	$4,000	$3,400	$3,900
2034	$4,100	$3,400	$4,000
2035*	$4,200	$3,500	$4,100
2036	$4,300	$3,600	$4,200
2037	$4,400	$3,700	$4,100
2038	$3,100	$2,200	$3,300
2039	$3,100	$2,300	$3,300
2040*	$3,200	$2,300	$3,400
2041	$3,300	$2,400	$3,500
2042	$3,300	$2,400	$3,500
PV	**$44,000**	**$38,000**	**$42,000**
EAV	**$4,300**	**$3,700**	**$4,000**

*Year in which air quality models were run. Benefits for all other years were extrapolated from years with model-based air quality estimates. Benefits calculated as value of avoided: $PM_{2.5}$-attributable deaths (quantified using a concentration-response relationship from the Pope et al. 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.

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 proposed 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

4-22. 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 4-22 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 proposed rules are expected to reduce fossil-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 proposed 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 (Agency for Toxic Substances and Disease Registry, 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, 2020c). 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, 2020b). 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 proposed 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 (2020a) 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.[115] 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 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

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

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 (2020a) 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 withdraws will also lower the number of aquatic organisms impinged and entrained by the power plant's water filtration and cooling systems.

4.5 Total Monetized Benefits

Table 4-23 through Table 4-26 present the combined monetized climate benefits and $PM_{2.5}$ and ozone-related health benefits for the three illustrative scenarios for the four snapshot years analyzed. Table 4-27 through Table 4-29 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 2042 timeframe.

Table 4-23 Combined Monetized Climate Benefits and $PM_{2.5}$ and O_3-related Health Benefits for the Illustrative Scenarios for 2028 (billions of 2019 dollars)

$SC\text{-}CO_2$ Discount Rate and Statistic	Climate Benefits Only[a]	Climate Benefits and $PM_{2.5}$ and O_3-related Health Benefits[b] (Discount Rate Applied to Health Benefits) 3%	7%
Proposal			
5% (average)	0.18	1.8	1.6
3% (average)	0.60	2.2	2.0
2.5% (average)	0.87	2.5	2.3
3% (95th percentile)	1.8	3.4	3.2
Less Stringent			
5% (average)	0.16	1.3	1.2
3% (average)	0.51	1.7	1.6
2.5% (average)	0.75	1.9	1.8
3% (95th percentile)	1.5	2.7	2.6
More Stringent			
5% (average)	0.0090	-0.41	-0.36
3% (average)	0.029	-0.39	-0.34
2.5% (average)	0.043	-0.37	-0.33
3% (95th percentile)	0.088	-0.33	-0.29

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

Table 4-24 Combined Monetized Climate Benefits and $PM_{2.5}$ and O_3-related Health Benefits for the Illustrative Scenarios for 2030 (billions of 2019 dollars)

SC-CO_2 Discount Rate and Statistic	Climate Benefits Only[a]	Climate Benefits and $PM_{2.5}$ and O_3-related Health Benefits[b] (Discount Rate Applied to Health Benefits) 3%	7%
Proposal			
5% (average)	1.7	16	14
3% (average)	5.4	20	18
2.5% (average)	7.9	22	21
3% (95th percentile)	16	31	29
Less Stringent			
5% (average)	1.6	14	13
3% (average)	5.0	18	17
2.5% (average)	7.3	20	19
3% (95th percentile)	15	28	27
More Stringent			
5% (average)	2.0	16	14
3% (average)	6.5	20	19
2.5% (average)	9.4	23	22
3% (95th percentile)	20	33	32

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

Table 4-25 Combined Monetized Climate Benefits and $PM_{2.5}$ and O_3-related Health Benefits for the Illustrative Scenarios for 2035 (billions of 2019 dollars)[a]

		Climate Benefits and $PM_{2.5}$ and O_3-related Health Benefits (Discount Rate Applied to Health Benefits)	
$SC\text{-}CO_2$ Discount Rate and Statistic	**Climate Benefits Only[a]**	**3%**	**7%**
Proposal			
5% (average)	0.81	5.5	5.0
3% (average)	2.5	7.1	6.6
2.5% (average)	3.5	8.2	7.7
3% (95th percentile)	7.5	12	12
Less Stringent			
5% (average)	0.78	4.7	4.3
3% (average)	2.4	6.3	5.9
2.5% (average)	3.4	7.3	6.9
3% (95th percentile)	7.2	11	11
More Stringent			
5% (average)	0.92	5.5	5.1
3% (average)	2.8	7.4	6.9
2.5% (average)	4.0	8.6	8.1
3% (95th percentile)	8.5	13	13

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

Table 4-26 Combined Monetized Climate Benefits and $PM_{2.5}$ and O_3-related Health Benefits for the Illustrative Scenarios for 2040 (billions of 2019 dollars)

SC-CO_2 Discount Rate and Statistic	Climate Benefits Only[a]	Climate Benefits and $PM_{2.5}$ and O_3-related Health Benefits[a] (Discount Rate Applied to Health Benefits) 3%	7%
Proposal			
5% (average)	0.59	4.2	3.8
3% (average)	1.7	5.3	4.9
2.5% (average)	2.4	6.0	5.6
3% (95th percentile)	5.3	8.8	8.5
Less Stringent			
5% (average)	0.55	3.1	2.9
3% (average)	1.6	4.2	3.9
2.5% (average)	2.2	4.8	4.6
3% (95th percentile)	4.9	7.5	7.2
More Stringent			
5% (average)	0.57	4.4	4.0
3% (average)	1.6	5.4	5.1
2.5% (average)	2.3	6.1	5.7
3% (95th percentile)	5.1	8.8	8.5

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

[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.

Table 4-27 Stream of Monetized Combined Climate Benefits and $PM_{2.5}$ and O_3-related Health Benefits for the Illustrative Proposal Scenario from 2024 through 2042 (billions of 2019 dollars)[a]

Year	Values Calculated using 3% Discount Rate			Values Calculated using 7% Discount Rate		
	Climate Benefits	$PM_{2.5}$ and O_3-related Health Benefits [b]	Total Benefits	Climate Benefits (discounted at 3%) [b]	$PM_{2.5}$ and O_3-related Health Benefits	Total Benefits
2024	-	-	-	-	-	-
2025	-	-	-	-	-	-
2026	-	-	-	-	-	-
2027	-	-	-	-	-	-
2028	0.60	1.6	2.2	0.60	1.4	2.0
2029	5.4	14	19	5.4	12	18
2030	5.4	14	20	5.4	13	18
2031	5.5	14	20	5.5	13	19
2032	2.3	4.3	6.6	2.3	3.9	6.2
2033	2.4	4.4	6.8	2.4	4.0	6.4
2034	2.4	4.5	6.9	2.4	4.1	6.5
2035	2.5	4.7	7.1	2.5	4.2	6.6
2036	2.5	4.8	7.3	2.5	4.3	6.8
2037	2.5	4.9	7.4	2.5	4.4	6.9
2038	1.7	3.4	5.1	1.7	3.1	4.7
2039	1.7	3.5	5.2	1.7	3.1	4.8
2040	1.7	3.6	5.3	1.7	3.2	4.9
2041	1.7	3.6	5.4	1.7	3.3	5.0
2042	1.8	3.7	5.5	1.8	3.3	5.1
PV[d]	**30**	**68**	**98**	**30**	**44**	**74**
EAV[d]	**2.1**	**4.8**	**6.9**	**2.1**	**4.3**	**6.4**

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

[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.

[c] For 7 percent PV and EAV calculations, climate benefits are discounted at 3 percent.

[d] The PV and EAV values in this table are for the timeframe of 2024 to 2042, not 2028 to 2042.

Table 4-28 Stream of Monetized Combined Climate Benefits and $PM_{2.5}$ and O_3-related Health Benefits for the Illustrative Less Stringent Scenario from 2024 through 2042 (billions of 2019 dollars)[a]

Year	Values Calculated using 3% Discount Rate			Values Calculated using 7% Discount Rate		
	Climate Benefits	$PM_{2.5}$ and O_3-related Health Benefits [b]	Total Benefits	Climate Benefits (discounted at 3%) [c]	$PM_{2.5}$ and O_3-related Health Benefits	Total Benefits
2024	-	-	-	-	-	-
2025	-	-	-	-	-	-
2026	-	-	-	-	-	-
2027	-	-	-	-	-	-
2028	0.51	1.2	1.7	0.51	1.0	1.6
2029	5.0	13	17	5.0	11	16
2030	5.0	13	18	5.0	12	17
2031	5.1	13	18	5.1	12	17
2032	2.2	3.6	5.9	2.2	3.3	5.5
2033	2.3	3.7	6.0	2.3	3.4	5.6
2034	2.3	3.8	6.1	2.3	3.4	5.8
2035	2.4	3.9	6.3	2.4	3.5	5.9
2036	2.4	4.0	6.4	2.4	3.6	6.0
2037	2.4	4.1	6.5	2.4	3.7	6.1
2038	1.5	2.5	4.0	1.5	2.2	3.8
2039	1.6	2.5	4.1	1.6	2.3	3.8
2040	1.6	2.6	4.2	1.6	2.3	3.9
2041	1.6	2.6	4.2	1.6	2.4	4.0
2042	1.6	2.7	4.3	1.6	2.4	4.0
PV[d]	**28**	**58**	**87**	**28**	**38**	**66**
EAV[d]	**2.0**	**4.1**	**6.0**	**2.0**	**3.7**	**5.7**

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

[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.

[c] For 7 percent PV and EAV calculations, climate benefits are discounted at 3 percent.

[d] The PV and EAV values in this table are for the timeframe of 2024 to 2042, not 2028 to 2042.

Table 4-29 Stream of Monetized Combined Climate Benefits and $PM_{2.5}$ and O_3-related Health Benefits for the Illustrative More Stringent Scenario from 2024 through 2042 (billions of 2019 dollars)[a]

Year	Values Calculated using 3% Discount Rate			Values Calculated using 7% Discount Rate		
	Climate Benefits	$PM_{2.5}$ and O_3-related Health Benefits [b]	Total Benefits	Climate Benefits (discounted at 3%) [c]	$PM_{2.5}$ and O_3-related Health Benefits	Total Benefits
2024	-	-	-	-	-	-
2025	-	-	-	-	-	-
2026	-	-	-	-	-	-
2027	-	-	-	-	-	-
2028	0.029	-0.42	-0.39	0.029	-0.37	-0.34
2029	6.4	13	20	6.4	12	18
2030	6.5	14	20	6.5	12	19
2031	6.6	14	20	6.6	12	19
2032	2.6	4.3	6.9	2.6	3.8	6.5
2033	2.7	4.4	7.1	2.7	3.9	6.6
2034	2.7	4.5	7.2	2.7	4.0	6.8
2035	2.8	4.6	7.4	2.8	4.1	6.9
2036	2.8	4.7	7.5	2.8	4.2	7.1
2037	2.9	4.5	7.4	2.9	4.1	7.0
2038	1.6	3.6	5.2	1.6	3.3	4.9
2039	1.6	3.7	5.3	1.6	3.3	5.0
2040	1.6	3.8	5.4	1.6	3.4	5.1
2041	1.7	3.9	5.5	1.7	3.5	5.1
2042	1.7	3.9	5.6	1.7	3.5	5.2
PV[d]	**34**	**65**	**99**	**34**	**42**	**76**
EAV[d]	**2.4**	**4.6**	**6.9**	**2.4**	**4.0**	**6.4**

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

[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.

[c] For 7 percent PV and EAV calculations, climate benefits are discounted at 3 percent.

[d] The PV and EAV values in this table are for the timeframe of 2024 to 2042, not 2028 to 2042.

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5 ECONOMIC IMPACT ANALYSIS

This section discusses potential energy and economic impacts, impacts on small entities, and labor impacts associated with this proposed rulemaking.[116] 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 proposed requirements. 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 these proposed 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 impacts of the proposed rules, EPA modeled an illustrative proposal scenario, as described in Section 1 and Section 3. This section provides a quantitative assessment of the energy price impacts for the illustrative proposal scenario and qualitative assessment of the factors that will in part determine the timing and magnitude of potential effects in other markets.

[116] Section 5 pertains to the analysis of the proposed standards for new natural gas-fired EGUs and for existing coal-fired EGUs. Please see Section 8 for impact analysis of the proposed standards for existing natural gas-fired EGUs and the third phase of the proposed standards for new natural gas-fired EGUs.

Table 5-1 summarizes projected changes in energy prices and fuel use resulting from the illustrative proposal scenario.

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

	2028	2030	2035	2040
Retail electricity prices	-1%	2%	0%	0%
Average price of coal delivered to the power sector	-1%	0%	2%	2%
Coal production for power sector use	-2%	-40%	-23%	-15%
Price of natural gas delivered to power sector	0%	9%	-2%	-3%
Price of average Henry Hub (spot)	0%	10%	-2%	-2%
Natural gas use for electricity generation	0%	8%	-1%	-2%

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 (2011 to 2021) for the energy market impacts listed:[117]

- The annual percent change in real electricity price over this period has been from -2.4 percent to 1.8 percent and averaged -0.8 percent.
- The percent change to the real annual price of coal for electricity generation has ranged from -7.3 percent to 3.1 percent over the past decade and averaged -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 -5.4 percent.
- The percent change to the average cost of natural gas for electricity generation has ranged from -36 percent to 108 percent over the past decade and averaged 3.6 percent.
- The percent change to annual natural gas use for electricity plants has ranged from -33.2 percent to 35.9 percent over the past decade and averaged -3.3 percent.

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

The projected energy market and electricity retail rate impacts of the proposed 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 wholesale energy prices and the changes in power generation were forecasted using IPM. The change in retail electricity prices reported in Chapter 3 is a national average across residential, commercial, and

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

industrial consumers. The change in electricity retail prices and bills were forecasted using outputs of IPM.

5.2 Social Costs

As discussed in EPA's *Guidelines for Preparing Economic Analyses*, social costs are the total economic burden of a regulatory action guidelines (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. Estimates of social costs may be compared to the social benefits expected because of a regulation to assess its net impact on society. The social costs of these rules will not necessarily be equal to the expenditures by the electricity sector and other affected industries to comply with the proposed requirements. As described is Section 3 above, these compliance costs are primarily calculated using the IPM. Table 3-7 above presents the total annual estimated compliance costs for EGUs for 2024 to 2042.

The compliance cost estimates from IPM for the proposed rules are the change in expenditures by the power sector to achieve and maintain compliance under each alternative. The production cost changes include changes in fuel expenditures. IPM solves for the least-cost approach to meet new regulatory requirements in the electricity sector with highly detailed information on electricity generation and air pollution control technologies and primary energy sector market conditions (coal and natural gas) while meeting fixed electricity demands, regulatory requirements, resource adequacy, and other constraints. However, potential effects outside of the electricity, coal and natural gas sectors are not evaluated within IPM. The estimated compliance costs do not equal social costs because they do not include a complete accounting of transfers and effects in other sectors of the economy.

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

Changes in the behavior of firms and households in response to the proposed rules could also interact with pre-existing distortions in the economy, such as taxes, resulting in additional social costs. In addition, the IRA provides investment, production, and fuel subsidies (i.e., ITC/PTC, 45Q and 45V) that are targeted to specific technologies EPA expects will be adopted to comply with regulatory requirements of these proposed rules. When modeling compliance with the proposed rules, IPM attempts to account for IRA subsidies in private technology adoption decisions in the electricity sector. See the IPM Documentation and Section 3 for further discussion of IRA representation in IPM, fuel and technology cost assumptions, and related uncertainties. While IPM estimates compliance costs incurred by the regulated firms, subsidy payments also represent real resource costs to the economy outside of the regulated sector. Thus, an economy-wide modeling approach would be necessary to account for changes in subsidy payments and associated social costs.

Economy-wide models—and, more specifically, computable general equilibrium (CGE) models—are analytical tools that can be used to evaluate the broad impacts of a regulatory action. A CGE-based approach to cost estimation concurrently considers the effect of a regulation across all sectors in the economy. In 2015, EPA established a Science Advisory Board (SAB) panel to consider the technical merits and challenges of using economy-wide models to evaluate costs, benefits, and economic impacts in regulatory analysis. In its final report, the SAB recommended that EPA begin to integrate CGE modeling into applicable regulatory analysis to offer a more comprehensive assessment of the effects of air regulations (U.S. EPA Science Advisory Board, 2017). In response to the SAB's recommendations, EPA developed a new CGE model called SAGE designed for use in regulatory analysis. A second SAB panel performed a peer review of SAGE, and the review concluded in 2020 (U.S. EPA Science Advisory Board, 2020). EPA used SAGE to evaluate potential economy-wide impacts of these proposed rules while accounting for IRA subsidies to technologies being used for compliance. This analysis is presented in Appendix B of the RIA. In section XIV(C) of the preamble to this proposed rule, EPA solicits comment on the SAGE analysis presented in appendix B.

5.3 Small Entity Analysis

5.3.1 Overview

For the proposed 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)[118] and is consistent with guidance published by the U.S. Small Business Administration's (SBA) Office of Advocacy that suggests that cost as a percentage of total revenues is a metric for evaluating cost increases on small entities in relation to increases on large entities.[119]

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 proposal 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

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[118] 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 >

[119] 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

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.6 database.

Based on these criteria, EPA identified a total of 53 GW of NGCC and 7 GW of NGCT 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[120], supplemented by research using S&P[121] and publicly available data.

Majority owners of power plants with affected EGUs were categorized as one of the seven ownership types.[122] 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.

[120] 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.
[121] The S&P database consists of detailed ownership and corporate affiliation information at the EGU level. For more information, see: www.capitaliq.spglobal.com
[122] 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.

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).[123] In these cases, 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.[124] SBA guidelines list all industries, along with their associated North American Industry Classification System (NAICS) code[125] 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 5-2. 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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[123] 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.

[124] SBA's table of size standards can be located here: https://www.sba.gov/document/support--table-size-standards.

[125] North American Industry Classification System can be accessed at the following link: https://www.census.gov/naics/

Table 5-2 SBA Size Standards by NAICS Code

NAICS Codes	NAICS U.S. Industry Title	Size Standards (millions of dollars)	Size Standards (number of employees)
221111	Hydroelectric Power Generation		500
221112	Fossil Fuel Electric Power Generation		750
221113	Nuclear Electric Power Generation		750
221114	Solar Electric Power Generation		250
221115	Wind Electric Power Generation		250
221116	Geothermal Electric Power Generation		250
221117	Biomass Electric Power Generation		250
221118	Other Electric Power Generation		250
221121	Electric Bulk Power Transmission and Control		500
221122	Electric Power Distribution		1,000
221210	Natural Gas Distribution		1,000
221310	Water Supply and Irrigation Systems	$41.0	
221320	Sewage Treatment Facilities	$35.0	
221330	Steam and Air-Conditioning Supply	$30.0	

Note: Based on size standards effective at the time EPA conducted this analysis (SBA size standards, effective December 19, 2022. Available at the following link: https://www.sba.gov/document/support--table-size-standards).
Source: SBA, 2022

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.[126] 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.[127] EPA primarily relied on data from the Ventyx database and the U.S. Census Bureau to inform this determination.

[126] Estimates of sales were used in lieu of revenue estimates when revenue data was unavailable.
[127] 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

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 8 percent of the NGCC and 10 percent of the NGCT additions over the historical period were attributed to small entities as summarized in Table 5-3 below.

Table 5-3 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	52.8	4.4	8%
NGCT	7.2	0.7	10%

In 2035, a new NGCC addition can comply with the proposed rule by implementing efficiency improvements (if it operates at an annual capacity factor of below 50 percent), co-firing hydrogen, or installing CCS. A new NGCT addition can comply with the proposed rule through implementing efficiency improvements (if it operates at an annual capacity factor of below 20 percent) 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[128], 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 proposal.

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,

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.

[128] 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 proposed 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 proposed rule was estimated by taking the difference in projected FOM, VOM and retrofit capital expenditures between the IPM estimates for the proposed 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 proposed rule was estimated by taking the difference in projected fuel expenditures between the IPM estimates for the proposed 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 proposed 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 proposal, 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 proposal, 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 proposed rule on NGCCs owned by small entities are summarized in Table 5-4. All costs are presented in 2019 dollars. EPA estimated the annual net compliance cost to small entities to be approximately $13 million in 2035.

Table 5-4 Projected Impact of the Proposed 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
Municipal	0	0	0
Private	6	11	0
Co-op	1	2	0
Total	**7**	**13**	**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 7 entities that own NGCC units considered in this analysis, none are projected to experience compliance costs greater than or equal to 1 percent of generation revenues in 2035.

5.4 Labor Impacts

This section discusses potential employment impacts of this regulation. As economic activity shifts in response to a regulation, typically there will be a mix of declines and gains in employment in different parts of the economy over time and across regions. To present a complete picture, an employment impact analysis will describe the potential positive and negative changes in employment levels. There are significant challenges when trying to evaluate the employment effects 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. We focus on impacts on labor demand related to compliance behavior. Environmental regulation may also affect labor supply through changes in worker health and productivity (Zivin and Neidell, 2018).

Economic theory of labor demand indicates that employers affected by environmental regulation may increase their demand for some types of labor, decrease demand for other types, or for still other types, not change 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), Greenstone (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. 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 proposed rule. EPA has a long history of analyzing the potential impacts of air pollution regulations on changes in the amount of labor needed in the power generation sector and 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.[129]

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 rule. The estimated employment difference between these scenarios can be interpreted as the incremental effect of the rule. 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 partial equilibrium modeling approach. It includes some of the potential ripple effects of these impacts on the broader economy. These potential ripple effects include the secondary job impacts in both upstream and downstream sectors. While the analysis includes impacts on upstream sectors including coal, natural gas, and uranium, it does not analyze 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 changes to energy markets (such as higher or lower forecasted electricity prices). This approach also excludes labor impacts that are sometimes reflected in a benefits analysis for an 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.[130] Detailed employment inventory data is available regarding recent employment related to coal, hydro,

[129] 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.

[130] https://www.usenergyjobs.org/

natural gas, geothermal, wind, and solar generation technologies. The data enables the creation of technology-specific factors that can be applied to model projections of capacity (reported in megawatts, or MW) and generation (reported in megawatt-hours, or MWh) in order to estimate impacts on employment. Since employment data is only available in aggregate by fuel type, it is necessary to disaggregate by labor type in order to differentiate between types of jobs or tasks for categories of workers. For example, some types of employment remain constant throughout the year and are largely a function of the size of a generator, e.g., fixed operation and maintenance activities, while others are variable and are related to the amount of electricity produced by the generator, e.g., variable operation and maintenance activities. The approach can be summarized in three basic steps:

- Quantify the total number of employees by fuel type in a given year;
- Estimate total fixed operating & maintenance (FOM), variable operating & maintenance (VOM), and capital expenditures by fuel type in that year; and
- Disaggregate total employees into three expenditure-based groups and develop factors for each group (FTE/MWh, FTE/MW-year, FTE/MW new capacity).

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.[131]

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 Proposed Rule

Electric generating units subject to these proposed rules will use various GHG mitigation measures to comply. Under the modeling of the proposal, 16 GW of coal and gas capacity is estimated to install CCS (similar to the baseline), 1 GW of coal-fired EGUs are projected to co-fire natural gas, and 21 GW of coal-fired capacity undertake coal to gas conversion (9 GW incremental to the baseline) in 2030. By 2030, the proposal is projected to result in an additional 1 GW of coal retirements, by 2035 an incremental 23 GW of coal retirements and by 2040, an incremental 18 GW of coal retirements relative to the baseline. Under the proposal in 2035 the

[131] While 2020 data is available in the 2021 version of this report, this section of the RIA utilizes 2019 data because this year does not reflect any short-term trends related to the COVID-19 pandemic. The annual report is available at: https://www.usenergyjobs.org/.

modeling projects an incremental 1 GW of NGCC, and an incremental 23 GW of NGCT additions relative to the baseline. Eleven GW of natural gas capacity is projected to co-fire with hydrogen by 2035. Two GW of incremental wind and solar additions and are also projected to occur relative to the baseline.

Based on these power sector modeling projections, we estimate an increase of over 9,000 construction-related job-years related to the installation of new pollution controls under the rule in 2030. In 2035, we estimate a decrease in construction-related job-years associated with pollution controls because some of those controls are projected to be built earlier under the rule, and some of that controlled capacity is projected to retire. We estimate a decrease of approximately 44,800 job-years in 2028 related to the construction of new capacity in that year, and an increase of approximately 51,100 construction-related job-years in 2030. In 2035 and 2040, we estimate an increase of 9,300 construction-related job-years and a decrease of 17,300 construction-related job-years, respectively. The relatively large near-term decrease followed by a relatively large increase and subsequent increase and decrease results primarily from relatively small temporal changes in the projected deployment of 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. The projected decrease in battery storage is related to the proposed new source standard, which is projected to generally result in a large increase in new NGCT capacity and a small decrease in new storage capacity. Without including battery storage in the total estimate, we would estimate increases in 2028, 2030, and 2035 of 12,000, 600, and 43,000 job-years, respectively, related to the construction of new capacity in those years, and a decrease of 19,000 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 5-5 represent a point estimate of incremental changes in construction jobs for each year (for a three-year construction projection, this table presents one-third of the total jobs for that project).

Table 5-5 Changes in Labor Utilization: Construction-Related (number of job-years of employment in a single year)

	2028	2030	2035	2040
New Pollution Controls	-300	9,300	-3,300	100
New Capacity	-44,800	51,100	9,300	-17,300

Notes: 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 over 2030 to 2040. The total net estimated decrease in recurring employment is about 25,000 job-years over 2028 to 2040, which is a small percentage of total 2019 power sector employment reported in the 2020 USEER (approximately 900,000 generation-related jobs, 75,000 coal-related jobs, and 276,000 natural gas-related jobs). Table 5-6 provide detailed estimates of recurring non-construction employment changes.

Table 5-6 Changes in Labor Utilization: Recurring Non-Construction (number of job-years of employment in a single year)

	2028	2030	2035	2040
Pollution Controls	<100	-300	<100	<100
Existing Capacity	-500	-18,000	-8,000	-6,000
New Capacity	1,100	1,500	4,400	3,300
Fuels (Coal, Natural Gas, Uranium)	-200	-700	-900	-600
Coal	*-400*	*-3,200*	*-800*	*-100*
Natural Gas	*100*	*2,600*	*-100*	*-500*
Uranium	*<100*	*<100*	*<100*	*<100*

Note: “<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. For EGUs, this proposed rule 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 include any estimates of the employment gains likely to result from the expected increase in hydrogen production, distribution, or use at EGUs. Furthermore, this analysis does not estimate the employment 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.[132] The Inflation Reduction Act also provides numerous incentives 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.[133]

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[132] 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

[133] 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 underserved communities through Federal government actions (86 FR 7009, January 20, 2021). EPA defines EJ as the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. EPA further defines the term fair treatment to mean that "no group of people should bear a disproportionate burden of environmental harms and risks, including those resulting from the negative environmental consequences of industrial, governmental, and commercial operations or programs and policies."[134] 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.[135] 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 groups of concern for both the baseline and proposed regulatory options, using the best available information (both quantitative and qualitative) to inform the decision-maker and the public.

[134] See, e.g., "Environmental Justice." *Epa.gov*, U.S. Environmental Protection Agency, 4 Mar. 2021, https://www.epa.gov/environmentaljustice.

[135] See https://www.epa.gov/environmentaljustice/technical-guidance-assessing-environmental-justice-regulatory-analysis.

A regulatory action may involve potential EJ concerns if it could: (1) create new disproportionate impacts on minority populations, low-income populations, and/or Indigenous peoples; (2) exacerbate existing disproportionate impacts on minority populations, low-income populations, and/or Indigenous peoples; or (3) present opportunities to address existing disproportionate impacts on minority populations, low-income populations, and/or Indigenous peoples through the action under development.

The Presidential Memorandum on Modernizing Regulatory Review (86 FR 7223; January 20, 2021) calls for procedures to "take into account the distributional consequences of regulations, including as part of a quantitative or qualitative analysis of the costs and benefits of regulations, to ensure that regulatory initiatives appropriately benefit, and do not inappropriately burden disadvantaged, vulnerable, or marginalized communities." Under 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,"[136] which provides recommendations that encourage analysts to conduct the highest quality analysis feasible, recognizing that data limitations, time, resource constraints, and analytical challenges will vary by media and circumstance.

A reasonable starting point for assessing the need for a more detailed EJ analysis is to review the available evidence from the published literature and from community input on what factors may make population groups of concern more vulnerable to adverse effects (e.g., underlying risk factors that may contribute to higher exposures and/or impacts). It is also important to evaluate the data and methods available for conducting an EJ analysis. EJ analyses can be grouped into two types, both of which are informative, but not always feasible for a given rulemaking:

1. **Baseline:** Describes the current (pre-control) distribution of exposures and risk, identifying potential disparities.

[136] 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 This Proposal

In addition to the benefits assessment (Section 4), EPA considers potential EJ concerns of these proposed rulemakings.[137] A potential EJ concern is defined as "the actual or potential lack of fair treatment or meaningful involvement of minority populations, low-income populations, tribes, and Indigenous peoples in the development, implementation and enforcement of environmental laws, regulations and policies."[138] For analytical purposes, this concept refers more specifically to "disproportionate impacts on minority populations, low-income populations, and/or Indigenous peoples that may exist prior to or that may be created by the proposed regulatory 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 population 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?

[137] Section 6 pertains to the analysis of the proposed standards for new natural gas-fired EGUs and for existing coal-fired EGUs. Please see Section 8 for impact analysis of the proposed standards for existing natural gas-fired EGUs and the third phase of the proposed standards for new natural gas-fired EGUs.
[138] See https://www.epa.gov/environmentaljustice/technical-guidance-assessing-environmental-justice-regulatory-analysis.

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 proposed rules are focused on climate impacts resulting from emission reductions directly targeted in this rulemaking, we begin with a qualitative discussion in Section 6.3. Insight into near-source pollutant emission changes associated with existing units is provided by demographic proximity analyses, including concerns related to specific control technologies such as CCS, although proximity analyses for new units are not feasible as their locations are unknown (Section 6.4).[139] $PM_{2.5}$ and ozone concentration changes due to this action are also quantitatively evaluated with respect to EJ impacts (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 (Section 6.6 and 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 Qualitative Assessment of Climate Impacts

In 2009, under the Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act ("Endangerment Finding"), the Administrator considered how climate change threatens the health and welfare of the U.S. population. As part of that consideration, she also considered risks to minority and low-income individuals and communities, finding that certain parts of the U.S. population may be especially vulnerable based on their characteristics or circumstances. These groups include economically and socially disadvantaged communities; individuals at vulnerable lifestages, such as the elderly, the very young, and pregnant or nursing women; those already in poor health or with comorbidities; the disabled; those experiencing homelessness, mental illness, or substance abuse; and/or Indigenous

[139] A discussion of potential EJ concerns related to CCS control strategies is available in the outreach and engagement section of the Preamble for this action, XIV(E)(3).

or minority populations dependent on one or limited resources for subsistence due to factors including but not limited to geography, access, and mobility.

Scientific assessment reports produced over the past decade by the U.S. Global Change Research Program (USGCRP), 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 poorer or predominantly non-White communities can be especially vulnerable to climate change impacts because they tend to have limited adaptive capacities and are more dependent on climate-sensitive resources such as local water and food supplies or have less access to social and information resources. Some communities of color, specifically populations defined jointly by ethnic/racial characteristics and geographic location, may be uniquely vulnerable to climate change health impacts in the U.S. 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, lifestages and ages are linked to immediate and future health impacts, and social determinants of health are linked to greater extent and severity of climate change-related health impacts (USGCRP, 2016).

In a 2021 report, EPA considered the degree to which four socially vulnerable populations—defined based on income, educational attainment, race and ethnicity, and age—may be more exposed to the highest impacts of climate change (U.S. EPA, 2021). The report found that Blacks and African American populations are approximately 40 percent more likely to currently live in these areas of the U.S. projected to experience the highest increases in mortality rates due to changes in temperature. Additionally, Hispanic and Latino individuals in weather-exposed industries were found to be 43 percent more likely to currently live in areas with the highest projected labor hour losses due to temperature changes. American Indian and Alaska Native individuals are projected to be 48 percent more likely to currently live in areas where the highest percentage of land may be inundated by sea level rise. Overall, the report confirmed findings of broader climate science assessments that Americans identifying as people of color, those with low-income, and those without a high school diploma face higher differential risks of experiencing the most damaging impacts of climate change.

6.4 Demographic Proximity Analyses of Existing Facilities

Demographic proximity analyses allow one to assess potentially vulnerable populations residing near affected facilities as a proxy for exposure and the potential for adverse health impacts that may occur at a local scale due to economic activity at a given location including noise, odors, traffic, and emissions under these EPA actions and not modeled elsewhere in this RIA.

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 without retirement or gas conversion plans before 2030 that are affected by these proposed rulemakings. Due to retirement plans of some plants, the following subsets of affected facilities were separately evaluated:

- All coal plants (140 facilities) with units potentially subject to the proposed 111 rules: Comparison of the percentage of various populations (race/ethnicity, age, education, poverty status, income, and linguistic isolation) living near the facilities to average national levels.
- Coal plants retiring by January 1, 2032 (3 facilities) with units potentially subject to the proposed 111 rules: Comparison of the percentage of various populations (race/ethnicity, age, education, poverty status, income, and linguistic isolation) living near the facilities to average national levels.[140]
- Coal plants retiring between January 1, 2032, to January 1, 2040, (19 facilities) with units potentially subject to the proposed 111 rules: Comparison of the percentage of various

[140] These three facilities are Comanche located in Colorado, Four Corners located in New Mexico, and Independence Steam Electric Station located in Arkansas.

populations (race/ethnicity, age, education, poverty status, income, and linguistic isolation) living near the facilities to average national levels.

The current analysis identified all census blocks with centroids within a 10 km and 50 km radius of the latitude/longitude location of each facility, and then linked each block with census-based demographic data.[141] 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.[142] 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., 10 km or 50 km) for all facilities was also computed (e.g., all EGUs potentially 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., 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., 10 km or 50 km) to the demographic composition of the nationwide population.

Table 6-1 and Table 6-2 show the results of the proximity analysis for the three sets of affected facilities investigated at the 10 km radius and the 50 km radius, respectively. The analysis indicates that, on average for all 140 units, the percentage of the population living within 10 km of these units that is African American, Hispanic/Latino, and Other/Multiracial is

[141] The 10 km distance was determined to be the shortest radius around these units that captured a large enough population to avoid excessive demographic uncertainty.

[142] The location of the Census block centroid is used to determine if the entire population of the Census block is assumed to be within the specified radius. It is unknown how sensitive these results may be to different methods of population estimation, such as aerial apportionment.

lower than the national average. The percent of the population that is American Indian within 10 km of the plants (0.8 percent) is above the national average (0.6 percent). This is driven by nine facilities that have a percent American Indian population living within 10 km ranging from 10.7 percent up to 70.3 percent (median is 14 percent). The percentage of the population living within 50 km of the facilities is below the national average percent for African American, American Indian, Hispanic/Latino, and Other Multi-racial demographics. In addition, the percentages of the population within 50 km that are living below poverty, below 2 times the poverty level, over 25 without a high school diploma, and in linguistic isolation are all below their corresponding national averages.

For the 19 coal plants retiring from January 1, 2032, to January 1, 2040, the percentage of the population living within 10 km of these units that is African American, American Indian, Hispanic/Latino, or Other Muti-racial are all below the corresponding national averages. In addition, the percentages of the population within 10 km that are living below poverty, below 2 times the poverty level, over 25 without a high school diploma, and in linguistic isolation are all below their corresponding national averages. When we look at the population living within 50 km of these 19 facilities, we see a larger percentage of the population is African American (15 percent), which is above the national average (12 percent). The other demographic percentages at 50 km are below their corresponding national averages.

For the three coal plants retiring by January 1, 2032, the percentage of the population living within 10 km and 50 km that are American Indian (3.8 percent at 10 km and 10.4 percent at 50 km) or Hispanic/Latino (46 percent at 10 km and 26 percent at 50 km) are substantially above their corresponding national averages (0.6 percent and 19 percent, respectively). The average percent of the population that is American Indian is driven by one facility in New Mexico with a percent American Indian population of 70 percent within 10 km and 35 percent within 50 km. Similarly, the average percent of the population that is Hispanic/Latino is driven by a facility in Colorado with a percent Hispanic/Latino population of 50 percent within 10 km and 41 percent within 50 km. The percentage of the population that is living below the poverty level (21 percent at 10 km and 18 percent at 50 km) and below 2 times the poverty level (45 percent at 10 km and 40 percent at 50 km) are substantially above their corresponding national averages (13 percent and 29 percent, respectively) for both distances. Note, that all three facilities drive the high poverty percentages.

Table 6-1 Proximity Demographic Assessment Results Within 10 km of Coal-Fired Units Greater than 25 MW Affected by these Proposed Rulemakings [a,b]

Population within 10 km				
Demographic Group	**Nationwide Average for Comparison**	**All Coal Plants subject to the proposed standard**	**Coal Plants Retiring by January 1, 2032, subject to the proposed standard**	**Coal Plants Retiring from January 1, 2032, to January 1, 2040, subject to the proposed standard**
Total Population	329,824,950	3,479,742	102,613	316,119
Number of Facilities	-	140	3	19
Race and Ethnicity by Percent				
White	60%	72%	45%	84%
African American	12%	9%	2%	4%
American Indian	0.6%	0.8%	3.8%	0.5%
Hispanic or Latino[b]	19%	12%	46%	5%
Other and Multiracial	9%	6%	3%	6%
Income by Percent				
Below Poverty Level	13%	14%	21%	13%
Below 2x Poverty Level	29%	32%	45%	29%
Education by Percent				
>25 and w/o a HS Diploma	12%	11%	12%	9%
Linguistically Isolated by Percent				
Linguistically Isolated	5%	2%	2%	1%

[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, African American, 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 6-2 Proximity Demographic Assessment Results Within 50 km of Coal-Fired Units Greater than 25 MW Affected by these Proposed Rulemakings [a,b]

Demographic Group	Nationwide Average for Comparison	All Coal Plants subject to the proposed standard	Coal Plants Retiring by January 1, 2032, subject to the proposed standard	Coal Plants Retiring from January 1, 2032, to January 1, 2040, subject to the proposed standard
Population within 50 km				
Total Population	329,824,950	51,062,363	382,473	10,594,472
Number of Facilities	-	140	3	19
Race and Ethnicity by Percent				
White	60%	68%	58%	70%
African American	12%	12%	2%	15%
American Indian	0.6%	0.5%	10.4%	0.4%
Hispanic or Latino[b]	19%	13%	26%	9%
Other and Multiracial	9%	6%	3%	6%
Income by Percent				
Below Poverty Level	13%	12%	18%	11%
Below 2x Poverty Level	29%	29%	40%	28%
Education by Percent				
>25 and w/o a HS Diploma	12%	10%	12%	10%
Linguistically Isolated by Percent				
Linguistically Isolated	5%	3%	2%	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, African American, 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[143] analysis aims to evaluate the potential for EJ concerns related to $PM_{2.5}$ and ozone exposures[144] among potentially vulnerable populations. To assess EJ ozone and $PM_{2.5}$ exposure impacts, we focus on the first and third of the three EJ questions from EPA's 2016 EJ Technical Guidance,[145] 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 being considered.[146]

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 proposed rulemakings, as well as the nature of known and potential exposures and impacts. Specifically, as 1) these proposed rules affects EGUs across the U.S., which typically have tall stacks that result in emissions from these sources being dispersed over large distances, and 2) both 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 illustrative scenarios, we conduct an analysis of changes in $PM_{2.5}$ and ozone concentrations resulting from the emission changes projected by IPM[147] to occur under the

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[143] The term exposure is used here to describe estimated $PM_{2.5}$ and ozone concentrations and not individual dosage.

[144] 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.

[145] 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

[146] 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).

[147] As discussed in greater detail in Section , 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

proposed rule as compared to the baseline scenario, characterizing average and distributional exposures following implementation of the proposed regulatory options in 2028, 2030, 2035, and 2040. However, several important caveats of this analysis are as follows:

- Although several future years were assessed for health benefits associated with these proposed 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 and 2040 represent EGU emissions expected in 2028, 2030, 2035 and 2040 respectively, but emissions from all other sources are projected to the year 2026. The 2028, 2030, 2035 and 2040 baselines therefore do not capture any anticipated changes in ambient ozone and $PM_{2.5}$ between 2026 and 2028, 2030, 2035 or 2040 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 but will not capture heterogenous changes in emissions from multiple facilities within a single state (i.e. all 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 are 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.

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 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.

Population variables considered in this EJ exposure assessment include race, ethnicity, educational attainment, employment status, health insurance status, linguistic isolation, poverty status, age, and sex (Table 6-3).[148]

Table 6-3 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
Linguistic Isolation	Speaks English "very well" or better; Speaks English less than "very well" OR Speaks English "well" or better; Speaks English less than "well"	0-99	Census tract
Poverty Status	Above the poverty line; Below the poverty line OR Above 2x the poverty line; Below 2x the poverty line	0-99	Census tract
Age	Children Adults Older Adults	0-17 18-64 65-99	Census tract
Sex	Female; Male	0-99	Census tract

6.5.1 Populations Predicted to Experience $PM_{2.5}$ and Ozone Air Quality Changes

IPM predicts the proposed rules will lead certain EGUs to decrease emissions, while others increase emissions, in the four snapshot years analyzed; therefore, the contiguous U.S. was first grouped into areas where air quality 1) does not change or improves, or 2) worsens as a result of the proposed rulemakings. Please note, national emissions reduction estimates vary by year, with 2030 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 policy scenarios analyzed except for the 2028 more stringent regulatory option, in

[148] 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).

which approximately 54 percent of the U.S. population is predicted to experience a $PM_{2.5}$ air quality improvement (Figure 6-1). In contrast, 50-97 percent of the U.S. population is predicted to experience ozone improvements (or lack of change) due to the proposed rulemakings and the other 3-50 percent are predicted to experience worsening ozone concentrations. In absolute terms, this equates to less than 81 million people experiencing worsening $PM_{2.5}$ concentrations (or up to 170 million in the 2028 more stringent regulatory option) and up to 196 million people experiencing worsening ozone concentrations. On average, the average magnitude of areas with worsening $PM_{2.5}$ concentration changes due to the rulemakings is much smaller than the magnitude of improving $PM_{2.5}$ concentration changes. Excluding the 2028 more stringent regulatory option, the magnitude of worsening ozone concentration changes is also smaller than that of improving ozone concentration changes, but to a lesser degree than $PM_{2.5}$.

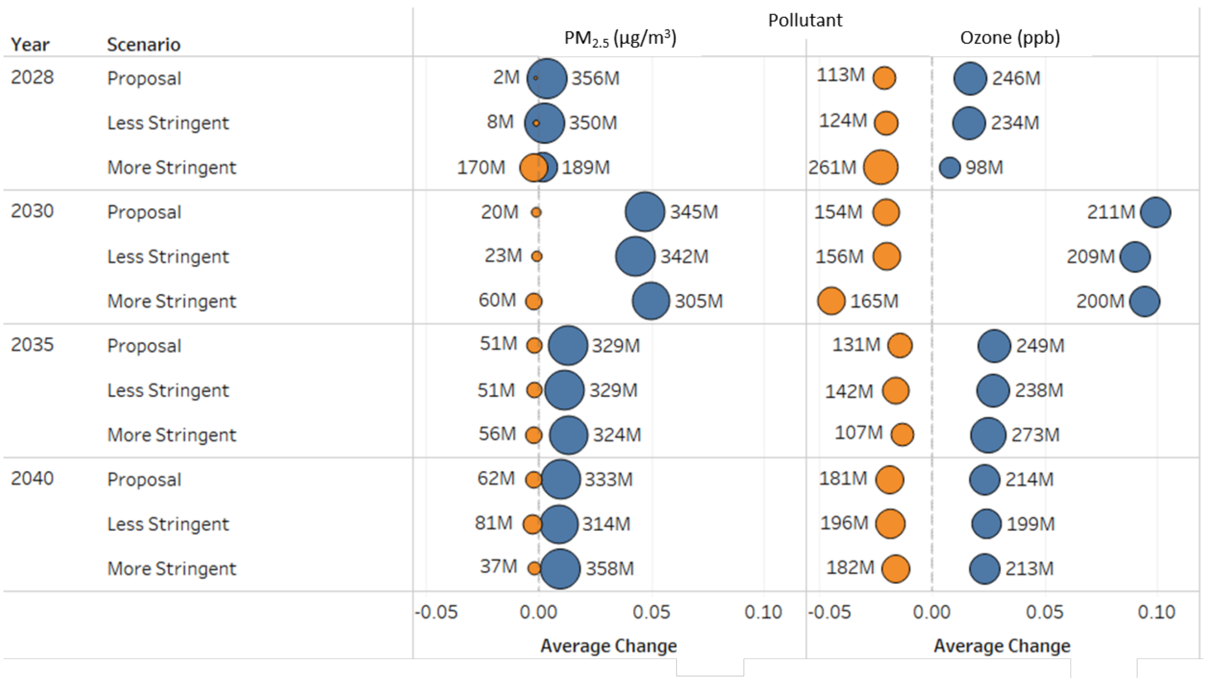

Figure 6-1 Number of People Residing in the Contiguous U.S. Areas Improving or Not Changing (Blue) or Worsening (Orange) in 2028, 2030, 2035, and 2040 for $PM_{2.5}$ and Ozone and the National Average Magnitude of Pollutant Concentration Changes ($\mu g/m^3$ and ppb) for the 3 Regulatory Options

6.5.2 $PM_{2.5}$ EJ Exposure Analysis

We evaluated the potential for EJ concerns among potentially vulnerable populations resulting from exposure to $PM_{2.5}$ under the baseline and proposed regulatory options in this rule.

This was done by characterizing the average and distribution of $PM_{2.5}$ exposures both prior to and following implementation of the three illustrative scenarios (the proposed regulatory option, as well as the less and more stringent regulatory options), in 2028, 2030, 2035, and 2040.

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 ($\mu g/m^3$) in 2028, 2030, 2035, and 2040 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). 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[149]), that is, populations with national average $PM_{2.5}$ concentrations higher than the reference population ordered from most to least difference are: those Linguistically isolated, Hispanics, Asians, Blacks, and the less educated (Figure 6-2).

In Figure 6-3, columns labeled "Proposal" "Less Stringent," and "More Stringent" provide information regarding how all three illustrative scenarios will impact $PM_{2.5}$ concentrations across various populations, respectively.[150] While the national-level $PM_{2.5}$ concentration reductions were similar for all population groups evaluated in 2028, 2035 and 2040, there were some differences observed in 2030. For example, (Figure 6-2), for all scenarios, the linguistically isolated, Asian population, and Hispanic population which also have higher

[149] https://www.federalregister.gov/documents/2023/01/27/2023-00269/reconsideration-of-the-national-ambient-air-quality-standards-for-particulate-matter

[150] 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.

average baseline exposures, are estimated to experience a slightly smaller $PM_{2.5}$ concentration reduction than the overall reference population.

The national-level assessment of $PM_{2.5}$ before and after implementation of these proposed rulemakings suggests that while EJ exposure disparities are present in the pre-policy scenario, meaningful EJ exposure concerns are not likely created or exacerbated by the rule for the population groups evaluated, due to the small difference in magnitudes of $PM_{2.5}$ concentration reductions across demographic groups.

		Year			
Population	**Qualifier**	2028	2030	2035	2040
Reference	Reference (0-99)	7.2	7.1	7.1	7.1
Race	White (0-99)	7.1	7.0	7.0	7.0
	American Indian (0-99)	6.7	6.7	6.6	6.6
	Asian (0-99)	7.8	7.7	7.6	7.6
	Black (0-99)	7.4	7.4	7.3	7.3
Ethnicity	Non-Hispanic (0-99)	7.0	6.9	6.8	6.8
	Hispanic (0-99)	8.0	7.9	7.9	7.8
Educational Attainment	More educated (>24: HS or more)	7.1	7.0	7.0	7.0
	Less educated (>24; no HS)	7.5	7.5	7.4	7.4
Employment Status	Employed (0-99)	7.3	7.3	7.2	7.2
	Unemployed (0-99)	7.2	7.1	7.1	7.1
	Not in the labor force (0-99)	7.2	7.1	7.1	7.1
Insurance Status	Insured (0-64)	7.2	7.2	7.1	7.1
	Unisured (0-64)	7.3	7.3	7.2	7.2
Linguistic Isolation	English "very well or better" (0-99)	7.1	7.1	7.0	7.0
	English < "very well" (0-99)	8.0	8.0	7.9	7.9
	English "well or better" (0-99)	7.1	7.1	7.0	7.0
	English < "well" (0-99)	8.2	8.1	8.1	8.0
Poverty Status	>200% of the poverty line (0-99)	7.1	7.1	7.0	7.0
	<200% of the poverty line (0-99)	7.3	7.3	7.2	7.2
	>Poverty line (0-99)	7.2	7.1	7.0	7.0
	<Poverty line (0-99)	7.4	7.3	7.3	7.2
Age	Adults (18-64)	7.2	7.2	7.1	7.1
	Children (0-17)	7.3	7.2	7.1	7.1
	Older Adults (65-99)	7.0	6.9	6.9	6.9
Sex	Females (0-99)	7.2	7.1	7.1	7.1
	Males (0-99)	7.2	7.1	7.1	7.1

Figure 6-2 Heat Map of the National Average $PM_{2.5}$ Concentrations in the Baseline Across Demographic Groups in 2028, 2030, 2035, and 2040 ($\mu g/m^3$)

Population	Qualifier	2028 Proposal	2028 Less Stringent	2028 More Stringent	2030 Proposal	2030 Less Stringent	2030 More Stringent	2035 Proposal	2035 Less Stringent	2035 More Stringent	2040 Proposal	2040 Less Stringent	2040 More Stringent
Reference	Reference (0-99)	0.00	0.00	0.00	0.03	0.03	0.03	0.01	0.01	0.01	0.01	0.01	0.01
Race	White (0-99)	0.00	0.00	0.00	0.03	0.03	0.03	0.01	0.01	0.01	0.01	0.01	0.01
	American Indian (0-99)	0.00	0.00	0.00	0.03	0.03	0.03	0.01	0.01	0.01	0.01	0.01	0.01
	Asian (0-99)	0.00	0.00	0.00	0.02	0.02	0.02	0.01	0.01	0.01	0.01	0.00	0.01
	Black (0-99)	0.00	0.00	0.00	0.03	0.03	0.03	0.01	0.01	0.01	0.01	0.01	0.01
Ethnicity	Non-Hispanic (0-99)	0.00	0.00	0.00	0.03	0.03	0.03	0.01	0.01	0.01	0.01	0.01	0.01
	Hispanic (0-99)	0.00	0.00	0.00	0.02	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.01
Educational Attainment	More educated (>24: HS or more)	0.00	0.00	0.00	0.03	0.03	0.03	0.01	0.01	0.01	0.01	0.01	0.01
	Less educated (>24; no HS)	0.00	0.00	0.00	0.03	0.03	0.03	0.01	0.01	0.01	0.01	0.01	0.01
Employment Status	Employed (0-99)	0.00	0.00	0.00	0.03	0.03	0.03	0.01	0.01	0.01	0.01	0.01	0.01
	Unemployed (0-99)	0.00	0.00	0.00	0.03	0.03	0.03	0.01	0.01	0.01	0.01	0.01	0.01
	Not in the labor force (0-99)	0.00	0.00	0.00	0.03	0.03	0.03	0.01	0.01	0.01	0.01	0.01	0.01
Insurance Status	Insured (0-64)	0.00	0.00	0.00	0.03	0.03	0.03	0.01	0.01	0.01	0.01	0.01	0.01
	Unisured (0-64)	0.00	0.00	0.00	0.03	0.03	0.03	0.01	0.01	0.01	0.01	0.01	0.01
Linguistic Isolation	English "very well or better" (0-99)	0.00	0.00	0.00	0.03	0.03	0.03	0.01	0.01	0.01	0.01	0.01	0.01
	English < "very well" (0-99)	0.00	0.00	0.00	0.02	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.01
	English "well or better" (0-99)	0.00	0.00	0.00	0.03	0.03	0.03	0.01	0.01	0.01	0.01	0.01	0.01
	English < "well" (0-99)	0.00	0.00	0.00	0.02	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.01
Poverty Status	>200% of the poverty line (0-99)	0.00	0.00	0.00	0.03	0.03	0.03	0.01	0.01	0.01	0.01	0.01	0.01
	<200% of the poverty line (0-99)	0.00	0.00	0.00	0.03	0.03	0.03	0.01	0.01	0.01	0.01	0.01	0.01
	>Poverty line (0-99)	0.00	0.00	0.00	0.03	0.03	0.03	0.01	0.01	0.01	0.01	0.01	0.01
	<Poverty line (0-99)	0.00	0.00	0.00	0.03	0.03	0.03	0.01	0.01	0.01	0.01	0.01	0.01
Age	Adults (18-64)	0.00	0.00	0.00	0.03	0.03	0.03	0.01	0.01	0.01	0.01	0.01	0.01
	Children (0-17)	0.00	0.00	0.00	0.03	0.03	0.03	0.01	0.01	0.01	0.01	0.01	0.01
	Older Adults (65-99)	0.00	0.00	0.00	0.03	0.03	0.03	0.01	0.01	0.01	0.01	0.01	0.01
Sex	Females (0-99)	0.00	0.00	0.00	0.03	0.03	0.03	0.01	0.01	0.01	0.01	0.01	0.01
	Males (0-99)	0.00	0.00	0.00	0.03	0.03	0.03	0.01	0.01	0.01	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, and 2040 ($\mu g/m^3$)

6.5.2.2 State Aggregated Results

We also provide $PM_{2.5}$ concentration reductions by state and demographic population in 2028, 2030, 2035, and 2040 for the 48 states in the contiguous U.S., for the proposed and more/less stringent regulatory options (Figure 6-4).[151] 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 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-

[151] 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.

level $PM_{2.5}$ concentration changes varies considerably across states. Depending on the year of analysis, average population-weighted state-level $PM_{2.5}$ concentrations are predicted to be reduced by up to 0.13 µg/m^3 (as seen in Nebraska in 2030). Increases in $PM_{2.5}$ concentrations for state-level average populations were rare and largest in 2030 and 2035 under the more stringent regulatory option in California, and only to a very small magnitude (~0.01 µg/m^3). When considering differences between demographic populations affected by a particular proposed 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 µg/m^3.[152] Therefore, whereas $PM_{2.5}$ exposure impacts vary by state, the small magnitude of differential impacts expected from the proposed rule is not likely to meaningfully exacerbate or mitigate EJ concerns within individual states.

[152] 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 Map of the State Average $PM_{2.5}$ Concentration Reductions (Blue) and Increases (Red) Due to the Three Illustrative Scenarios Across Demographic Groups in 2028, 2030, 2035, and 2040 (µg/m^3)

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., Hispanics) in the contiguous U.S. experience what change in $PM_{2.5}$ concentrations compared to what percentage of the overall reference group (i.e., the total population of contiguous U.S.) experiences similar concentration changes from EGU emission changes under the three regulatory options in 2028, 2030, 2035, and 2040 (Figure 6-5).

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 account for potential difference in underlying susceptibility, vulnerability, or risk factors across populations to $PM_{2.5}$ exposure. Nor could we include information about differences in other factors that could affect the likelihood of adverse impacts (e.g., exercise patterns) across groups.

As the baseline scenario is similar to that described by other RIAs (e.g., the Regulatory Impact Analysis for the Proposed Reconsideration of the National Ambient Air Quality Standards for Particulate Matter)[153], we focus on the $PM_{2.5}$ changes due to this proposed rulemaking. The vast majority of each demographic population are predicted to experience $PM_{2.5}$ concentration changes less than 0.06 $\mu g/m^3$ under any regulatory option for all four future years analyzed. While the greatest impacts, and the greatest differential impacts across population, occurs in 2030, 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, and 2040 distributional analyses of $PM_{2.5}$ concentration changes under the various regulatory options suggests that the proposed rules are not likely to meaningfully exacerbate or mitigate EJ $PM_{2.5}$ exposure concerns for population groups evaluated.

[153] https://www.epa.gov/system/files/documents/2023-01/naaqs-pm_ria_proposed_2022-12.pdf

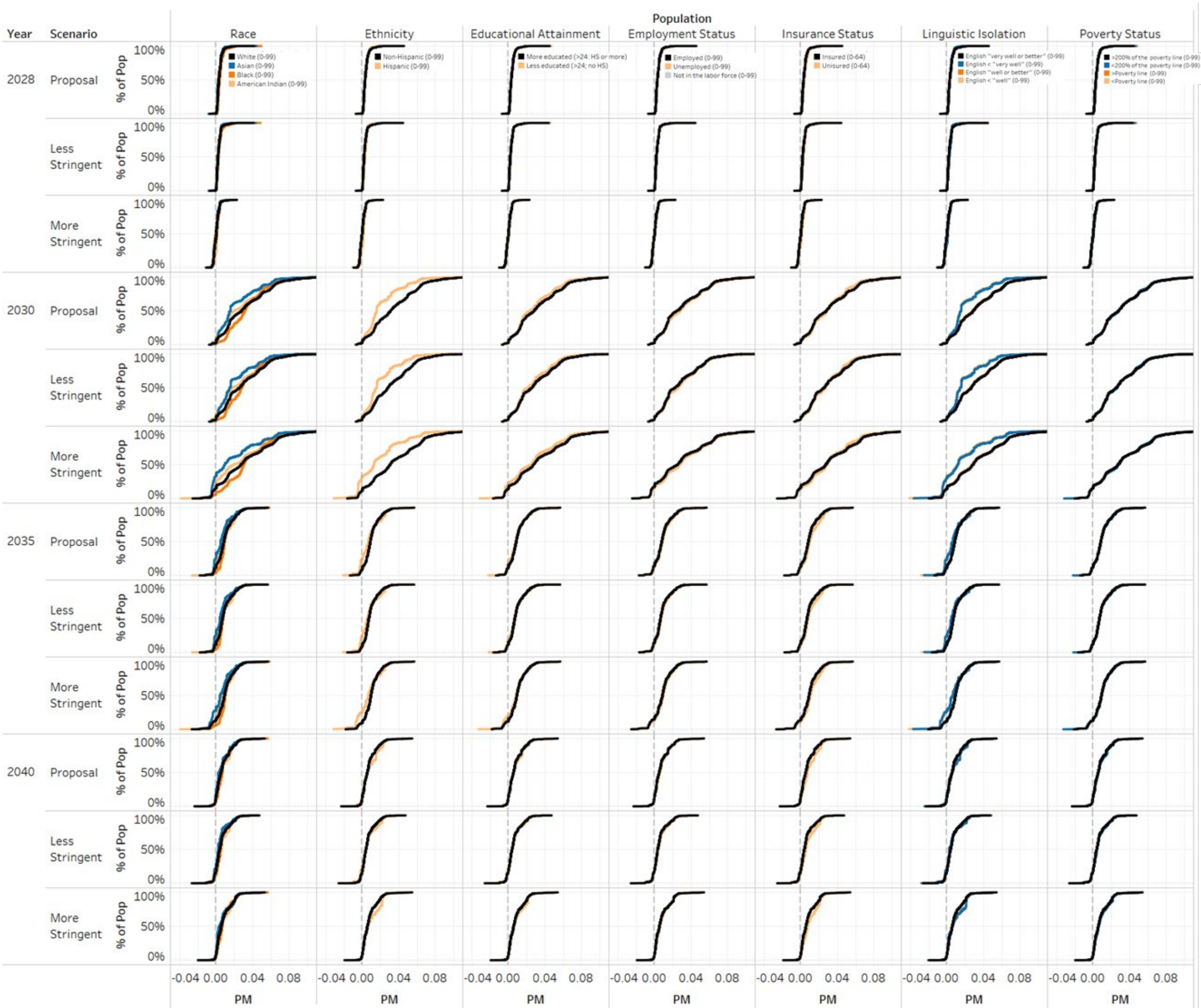

Figure 6-5 Distributions of $PM_{2.5}$ Concentration (µg/m^3) Changes Across Populations, Future Years, and Regulatory Options

6.5.3 Ozone EJ Exposure Analysis

To evaluate the potential for EJ concerns among potentially vulnerable populations resulting from exposure to ozone under the baseline and regulatory options proposed in this rule, we characterize the distribution of ozone exposures both prior to and following implementation of the proposed rule, as well as under the more and less stringent regulatory options, in 2028, 2030, 2035, and 2040.

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 (see

Sections 3.8 and 4.3.8 for discussions of uncertainty). In addition to the small magnitude of differential ozone concentration changes associated with these proposed 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 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.[154] 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.

[154] Level of 70 ppb with an annual fourth-highest daily maximum eight-hour concentration, averaged over three years.

6.5.3.1 National Aggregated Results

National average baseline ozone concentrations in ppb in 2028, 2030, 2035, and 2040 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 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. Populations with national average ozone concentrations higher than the reference population ordered from most to least difference were: American Indians, Hispanics, the Linguistically isolated, Asians, the Less educated, and Children. Average national disparities observed in the baseline of this rule are fairly consistent across the four future years and similar to those described by recent rules (e.g., the Regulatory Impact Analysis for Proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard).[155]

In Figure 6-7, columns labeled “Proposal” “Less Stringent,” and “More Stringent” provide information regarding how the three illustrative scenarios will impact ozone concentrations across various populations.[156] All national-level ozone concentration changes of these proposed rulemakings across population groups, years, and regulatory options are predicted to be relatively small in absolute magnitude (i.e., <0.04 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 2030 for Asian populations, Hispanic populations, 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.

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

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155 https://www.epa.gov/system/files/documents/2022-03/transport_ria_proposal_fip_2015_ozone_naaqs_2022-02.pdf

156 We report average exposure results to the decimal place where difference between demographic populations become visible, as we cannot provide a quantitative estimate of the air quality modeling precision uncertainty. Using this approach allows for a qualitative consideration of uncertainties and the significance of the relatively small differences.

population groups evaluated, ozone EJ exposure disparities may be exacerbated for some population groups analyzed in 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 relative to baseline disparities in ozone concentrations across population groups.

Population	Qualifier	Year 2028	2030	2035	2040
Reference	Reference (0-99)	40.8	40.7	40.5	40.4
Race	White (0-99)	40.9	40.8	40.6	40.5
	American Indian (0-99)	42.9	42.9	42.7	42.7
	Asian (0-99)	42.0	41.9	41.6	41.4
	Black (0-99)	39.5	39.4	39.2	39.0
Ethnicity	Non-Hispanic (0-99)	40.3	40.2	39.9	39.8
	Hispanic (0-99)	42.8	42.6	42.4	42.3
Educational Attainment	More educated (>24: HS or more)	40.6	40.5	40.3	40.3
	Less educated (>24; no HS)	41.2	41.1	41.0	40.9
Employment Status	Employed (0-99)	41.2	41.1	41.0	40.9
	Unemployed (0-99)	40.8	40.7	40.5	40.4
	Not in the labor force (0-99)	40.8	40.7	40.5	40.4
Insurance Status	Insured (0-64)	41.0	40.8	40.7	40.6
	Unisured (0-64)	40.5	40.4	40.2	40.1
Linguistic Isolation	English "very well or better" (0-99)	40.7	40.6	40.4	40.3
	English < "very well" (0-99)	42.1	42.0	41.8	41.8
	English "well or better" (0-99)	40.7	40.6	40.4	40.4
	English < "well" (0-99)	42.2	42.1	41.9	41.8
Poverty Status	>200% of the poverty line (0-99)	40.8	40.7	40.5	40.4
	<200% of the poverty line (0-99)	40.8	40.7	40.5	40.4
	>Poverty line (0-99)	40.8	40.7	40.5	40.4
	<Poverty line (0-99)	40.8	40.7	40.5	40.4
Age	Adults (18-64)	40.9	40.7	40.6	40.5
	Children (0-17)	41.0	40.9	40.7	40.6
	Older Adults (65-99)	40.4	40.3	40.1	40.1
Sex	Females (0-99)	40.8	40.7	40.5	40.4
	Males (0-99)	40.8	40.7	40.5	40.4

Figure 6-6 Heat Map of the National Average Ozone Concentrations in the Baseline Across Demographic Groups in 2028, 2030, 2035, and 2040 (ppb)

Population	Group (age)	2028 Proposal	2028 Less Stringent	2028 More Stringent	2030 Proposal	2030 Less Stringent	2030 More Stringent	2035 Proposal	2035 Less Stringent	2035 More Stringent	2040 Proposal	2040 Less Stringent	2040 More Stringent
Reference	Reference (0-99)	0.01	0.01	-0.01	0.03	0.02	0.01	0.01	0.01	0.01	0.00	0.00	0.00
Race	White (0-99)	0.01	0.01	-0.01	0.03	0.03	0.02	0.01	0.01	0.01	0.00	0.00	0.00
	American Indian (0-99)	0.01	0.01	-0.01	0.03	0.02	0.03	0.01	0.01	0.01	0.01	0.00	0.01
	Asian (0-99)	0.01	0.01	-0.02	0.00	0.00	-0.01	0.01	0.01	0.01	0.00	0.00	0.00
	Black (0-99)	0.01	0.01	-0.01	0.03	0.02	0.00	0.01	0.01	0.01	0.00	0.00	0.00
Ethnicity	Non-Hispanic (0-99)	0.01	0.01	-0.01	0.04	0.03	0.02	0.01	0.01	0.01	0.00	0.00	0.00
	Hispanic (0-99)	0.01	0.01	-0.02	0.00	-0.01	0.00	0.01	0.01	0.01	0.00	0.00	0.00
Educational Attainment	More educated (>24: HS or more)	0.01	0.01	-0.01	0.03	0.03	0.02	0.01	0.01	0.01	0.00	0.00	0.00
	Less educated (>24; no HS)	0.01	0.01	-0.02	0.02	0.01	0.01	0.01	0.00	0.01	0.00	0.00	0.00
Employment Status	Employed (0-99)	0.01	0.01	-0.02	0.02	0.02	0.01	0.01	0.01	0.01	0.00	0.00	0.00
	Not in the labor force (0-99)	0.01	0.01	-0.01	0.03	0.02	0.01	0.01	0.01	0.01	0.00	0.00	0.00
	Unemployed (0-99)	0.01	0.01	-0.01	0.03	0.02	0.01	0.01	0.01	0.01	0.00	0.00	0.00
Insurance Status	Insured (0-64)	0.01	0.01	-0.02	0.03	0.02	0.01	0.01	0.01	0.01	0.00	0.00	0.00
	Unisured (0-64)	0.01	0.01	-0.01	0.02	0.02	0.01	0.01	0.01	0.01	0.00	0.00	0.00
Linguistic Isolation	English "very well or better" (0-99)	0.01	0.01	-0.01	0.03	0.03	0.02	0.01	0.01	0.01	0.00	0.00	0.00
	English < "very well" (0-99)	0.01	0.01	-0.02	0.00	-0.01	-0.01	0.01	0.01	0.01	0.00	0.00	0.00
	English "well or better" (0-99)	0.01	0.01	-0.01	0.03	0.03	0.02	0.01	0.01	0.01	0.00	0.00	0.00
	English < "well" (0-99)	0.01	0.01	-0.02	-0.01	-0.01	-0.01	0.01	0.01	0.01	0.00	0.00	0.00
Poverty status	>200% of the poverty line (0-99)	0.01	0.01	-0.01	0.03	0.02	0.01	0.01	0.01	0.01	0.00	0.00	0.00
	<200% of the poverty line (0-99)	0.01	0.01	-0.01	0.03	0.02	0.02	0.01	0.01	0.01	0.00	0.00	0.00
	>Poverty line (0-99)	0.01	0.01	-0.01	0.03	0.02	0.01	0.01	0.01	0.01	0.00	0.00	0.00
	<Poverty line (0-99)	0.01	0.01	-0.02	0.03	0.02	0.02	0.01	0.00	0.01	0.00	0.00	0.00
Age	Adults (18-64)	0.01	0.01	-0.01	0.03	0.02	0.01	0.01	0.01	0.01	0.00	0.00	0.00
	Children (0-17)	0.01	0.01	-0.01	0.03	0.02	0.02	0.01	0.01	0.01	0.00	0.00	0.00
	Older Adults (65-99)	0.01	0.01	-0.01	0.03	0.03	0.02	0.01	0.01	0.01	0.00	0.00	0.00
Sex	Females (0-99)	0.01	0.01	-0.01	0.03	0.02	0.01	0.01	0.01	0.01	0.00	0.00	0.00
	Males (0-99)	0.01	0.01	-0.01	0.03	0.02	0.02	0.01	0.01	0.01	0.00	0.00	0.00

Figure 6-7 Heat Map of Reductions (Green) and Increases (Red) in National Average Ozone Concentrations Due to the Three Illustrative Scenarios Across Demographic Groups in 2028, 2030, 2035, and 2040 (ppb)

6.5.3.2 State Aggregated Results

We also provide ozone concentration reductions by state and demographic population in 2028, 2030, 2035, and 2040 for the 48 states in the contiguous U.S., for the policy and more stringent regulatory alternatives (Figure 6-8). 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 0.52 ppb (observed for Black populations in Nebraska [NE] under the "More Stringent Scenario" in 2030). 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 "More Stringent" policy option in 2030 with a maximum state-level population-weighted average of 0.18 ppb experienced by Asian populations in Delaware (DE) and by Asians, American Indians, Blacks, Hispanics, the Linguistically isolated, the Less educated, and Uninsured populations in Maryland (MD). 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., Pennsylvania [PA] in 2030 and Virginia [VA] in 2030 and 2035).

When comparing exposure impacts across demographic groups within states, most states display similar impacts across demographic groups in 2028, 2035, and 2040. However, some 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 ~0.07 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, and 2040, ozone EJ exposure disparities at the state level may be either mitigated or exacerbated for some population groups analyzed in 2030 under the various regulatory options. However, the extent to which disparities may be exacerbated is likely modest, due to the small magnitude of the ozone concentration changes relative to the magnitude of baseline ozone exposure disparities.

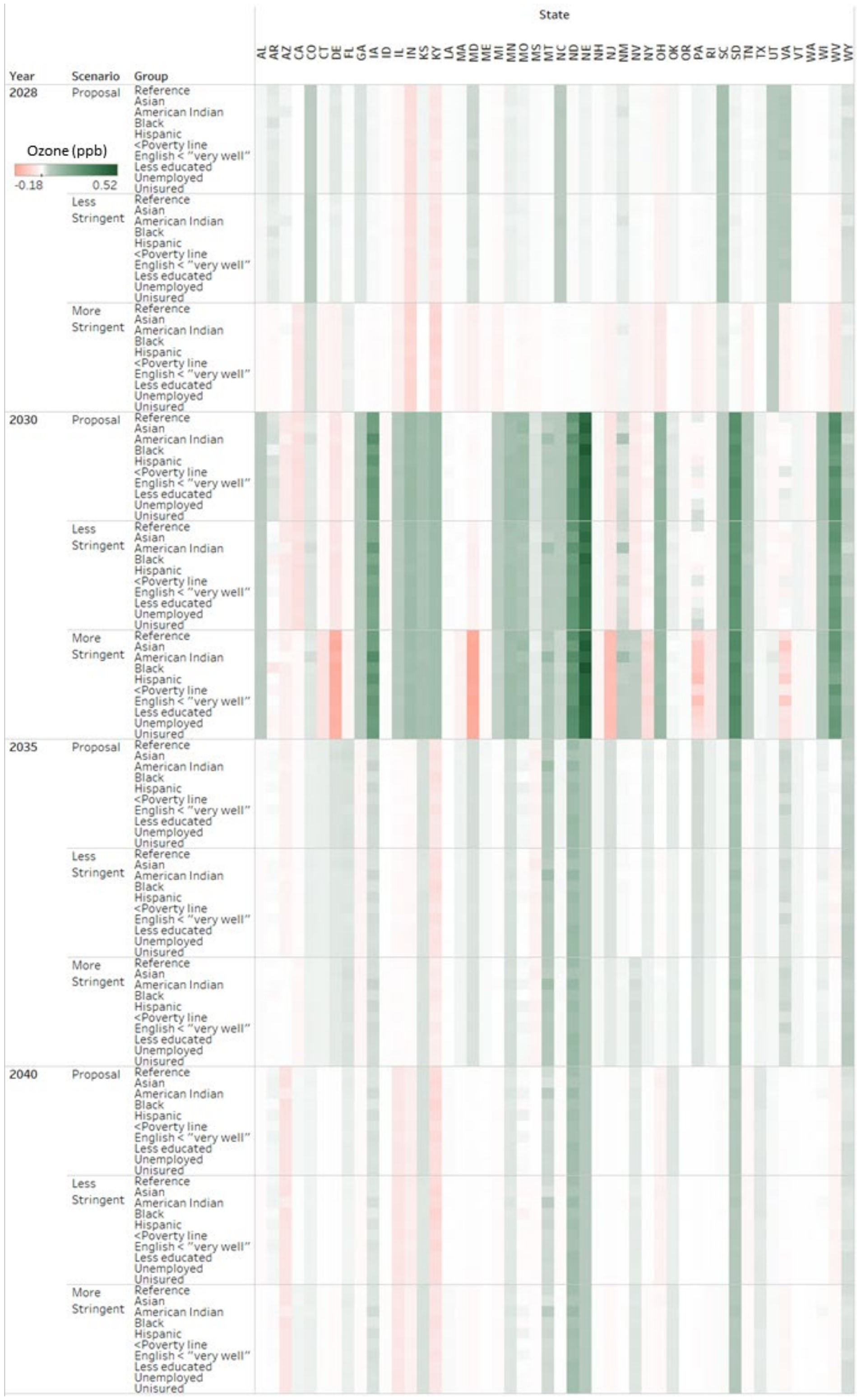

Figure 6-8 Heat Map of the State Average Ozone Concentrations Reductions (Green) and Increases (Red) Due to the Three Illustrative Scenarios Across Demographic Groups in 2028, 2030, 2035. and 2040 (ppb)

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., Hispanics) 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 illustrative scenarios in 2028, 2030, 2035, and 2040.

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 account for potential difference in underlying susceptibility, vulnerability, or risk factors across populations expected to experience post-policy ozone exposure changes. 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 Proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard)[157], we focus on the ozone changes due to these proposed rulemakings. Distributions of 12 km gridded ozone concentration changes from EGU control strategies of affected facilities under the illustrative scenarios analyzed in these proposed rulemakings are shown in Figure 6-9. When comparing distributional exposure impacts across demographic groups, similar impacts are predicted to occur across demographic groups in 2028, 2035, and 2040. However, certain groups, specifically Asians, Hispanics, and those linguistically isolated, may experience smaller ozone exposure reductions across the population distributions in 2030, as compared to the overall reference distribution.

Therefore, the distributional assessment of ozone exposure changes due to the regulatory options suggests that while most illustrative scenarios and future years analyzed will not likely mitigate or exacerbate ozone EJ exposure disparities for the population groups evaluated in 2028, 2035, and 2040, distributional ozone EJ exposure disparities may be exacerbated for some population groups analyzed in 2030 under all illustrative scenarios. However, the extent to which

[157] https://www.epa.gov/system/files/documents/2022-03/transport_ria_proposal_fip_2015_ozone_naaqs_2022-02.pdf

disparities may be exacerbated is likely modest, due to the small magnitude of the ozone concentration changes.

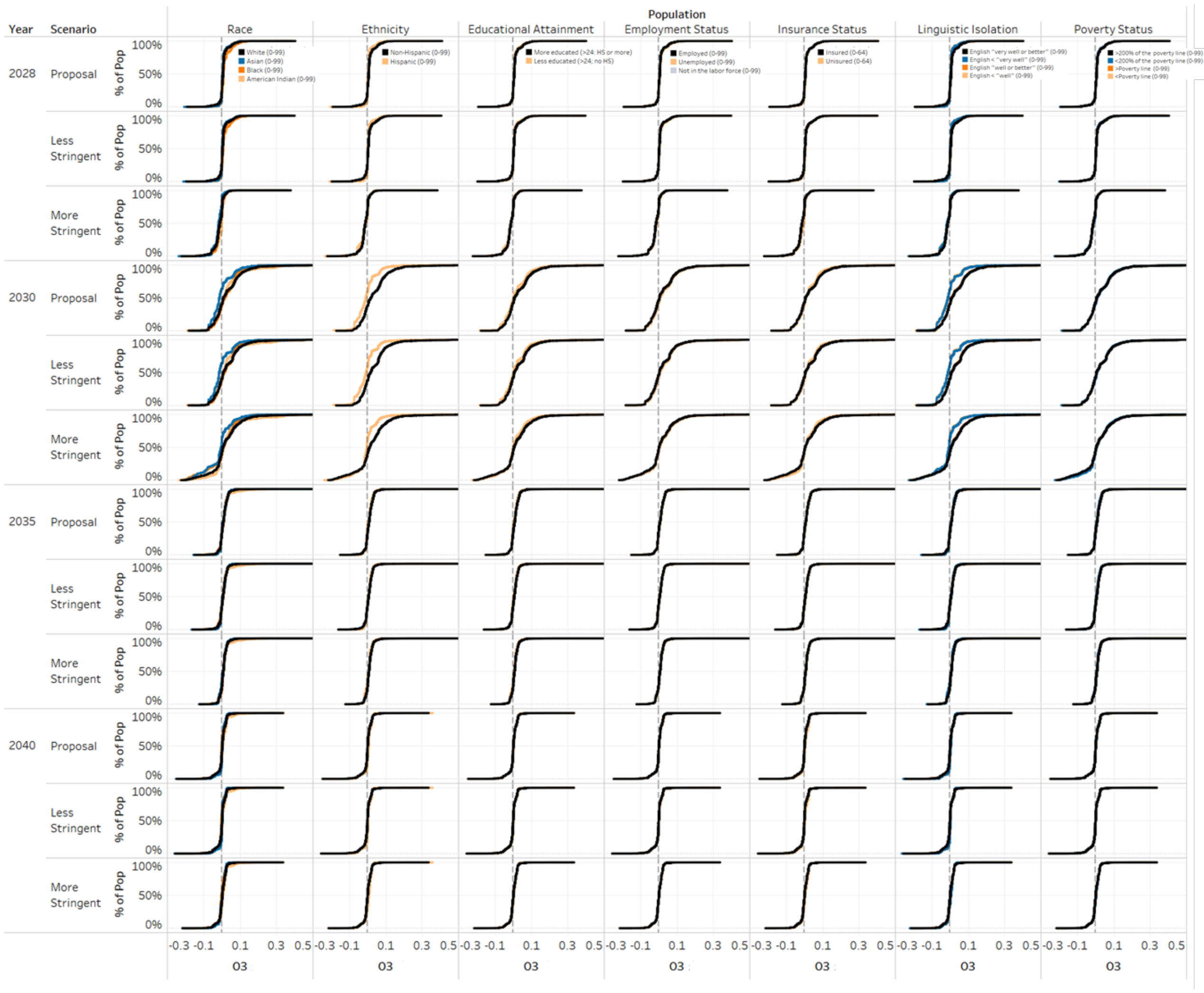

Figure 6-9 Distributions of Ozone Concentration Changes (ppb) Across Populations, Future Years, and Regulatory Options

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 proposed rulemakings (Section 3.8).

While quantitative impacts are not analyzed, we can qualitatively speak to the expected $PM_{2.5}$-attributable mortality EJ impacts of this proposal, 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/African Americans, 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 illustrative scenarios 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 this proposed rule, 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 depends on mutually exclusive assumptions, was performed to answer separate questions, and is associated with unique limitations and uncertainties.

Baseline demographic proximity analyses provide information as to whether there may be potential EJ concerns associated with environmental stressors. In this case, our proximity analysis of the full population of potentially affected units greater than 25 MW (140 units) indicated that the demographic percentages of the population within 10 km and 50 km of the facilities are relatively similar to the national averages. The proximity analysis of the 19 units that will retire from January 1, 2032, to January 1, 2040, (a subset of the total 140 units) found that the percent of the population within 10 km that is African American (15 percent) is higher than the national average (12 percent). The proximity analysis for the 3 units that will retire by January 1, 2032, (a subset of the total 140 units) found that for both the 10 km and 50 km populations: the percent of the population that is American Indian for one facility (4 percent at 10 km and 10 percent at 50 km) is substantially above the national average (0.8 percent), the percent of the population that is Hispanic/Latino for another facility (46 percent at 10 km and 26 percent at 50 km) is substantially above the national average (19 percent), and finally, all three facilities were well above the national average for both the percent below the poverty level and the percent below two times the poverty level.

While the demographic proximity analyses may appear to parallel the baseline analysis of nationwide ozone and $PM_{2.5}$ exposures in certain ways, the two should not be directly compared. The baseline ozone and $PM_{2.5}$ exposure assessments are in effect an analysis of total burden in the contiguous U.S., and include various assumptions, such as the implementation of promulgated regulations. It serves as a starting point for both the estimated ozone and $PM_{2.5}$ changes due to this proposal 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). Baseline $PM_{2.5}$ and ozone exposure analyses show that certain populations, such as Hispanic, Asian, those linguistically isolated, and the less educated may experience disproportionately higher ozone and $PM_{2.5}$ exposures as compared to the national average. Black populations may also experience disproportionately higher $PM_{2.5}$ concentrations than the reference group, and American Indian populations 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 this proposed rulemaking 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. 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 this rulemaking across demographic populations, relative to baseline burden disparities (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 of potential EJ concerns will be meaningfully exacerbated or mitigated by the regulatory alternatives under consideration regarding $PM_{2.5}$ exposures in all future years evaluated and ozone exposures in 2028, 2035, and 2040. However, in 2030, Asian populations, Hispanic populations, and those linguistically isolated may experience a slight exacerbation of ozone exposure disparities at the national level (EJ question 3). At the state level, ozone exposure disparities may be either mitigated or exacerbated for certain demographic groups analyzed in 2030, also to a small degree. Importantly, the action described in these rules are expected to lower ozone and $PM_{2.5}$ for most people, including those areas that struggle to attain or maintain the NAAQS, and thus mitigate some pre-existing health risks across all populations evaluated.

This EJ air quality analysis concludes that there are disparities across various populations in the pre-policy baseline scenario (EJ question 1) and infer that these disparities are likely to persist after promulgation of this proposed rulemaking (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 illustrative scenarios analyzed will not likely mitigate or exacerbate ozone exposure disparities for the population groups evaluated, ozone exposure disparities may be exacerbated for some population groups analyzed in 2030 under all illustrative scenarios. However, the extent to which disparities may be exacerbated 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 this proposal 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.

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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.[158] All cost and benefit analysis begins in 2028, except for monitoring, reporting, and recordkeeping (MR&R), as some MR&R costs are estimated to begin in 2024. The regulatory impacts are evaluated for the specific snapshot years of 2028, 2030, 2035, and 2040. We also estimate the present value (PV) of costs, benefits, and net benefits, calculated for the years 2024 to 2042 from the perspective of 2024, using both a three percent and seven percent discount rate as directed by OMB's Circular A-4. All dollars are in 2019 dollars. We also present the equivalent annual value (EAV), which represents a flow of constant annual values that, had they occurred in each year from 2024 to 2042, would yield a sum equivalent to the PV. The EAV represents the value of a typical cost or benefit for each year of the analysis, in contrast to the specific snapshot-year estimates reported in the costs and benefits sections of this RIA.

There are potential benefits and costs that may result from the proposed rules that have not been quantified or monetized. Due to current data and modeling limitations, our estimates of the benefits from reducing CO_2 emissions do not include important impacts like ocean acidification or potential tipping points in natural or managed ecosystems. 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 proposed rules.

The compliance costs reported in this RIA are not social costs although in this analysis we use compliance costs as a proxy for social costs. We do not account for changes in costs and benefits due to changes in economic welfare in the broader economy arising from shifts in

[158] Section 7 pertains to the analysis of the proposed standards for new natural gas-fired EGUs and for existing coal-fired EGUs. Please see Section 8 for impact analysis of the proposed standards for existing natural gas-fired EGUs and the third phase of the proposed standards for new natural gas-fired EGUs.

production and consumption that may be induced by the proposed requirements. Furthermore, costs 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 proposal. 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 2042, using both a three percent and seven percent discount rate 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 one less stringent and one more stringent illustrative scenario relative to the illustrative proposal scenario.

This calculation of a PV requires an annual stream of values for each year of the 2024 to 2042 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, and 2040. The proposed 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 alone, the 2030 projection year is representative of 2029 through 2031, the 2035 projection year is representative of 2032 to 2037, and the 2040 projection year is representative of 2038 to 2042. 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 interim 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

We first present net benefit analysis for the three years of detailed analysis, 2028, 2030, 2035, and 2040. 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, and 2040, respectively. The comparison of benefits and costs in PV and EAV terms for the proposed rules can be found in Table 7-5 for the illustrative proposal scenario; Table 7-6 presents the results for the less stringent illustrative scenario; and Table 7-7 presents results for the more stringent illustrative scenario. Estimates in the tables are presented as rounded values.

As discussed in Section 4 of this RIA, the monetized benefits estimates provide an incomplete overview of the beneficial impacts of the proposal. 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 proposed rules are not quantified or monetized. EPA anticipates that taking non-monetized effects into account would show the proposals 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 proposals exceed the costs by billions of dollars annually.

We also note that the RIA follows EPA's historic 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 Appendix B of this RIA, EPA has also included an economy-wide analysis that considers additional facets of the economic response to the proposed rules, including the full resource requirements of the expected compliance pathways, some of which are paid for through subsidies in the partial equilibrium analysis. The social cost estimates in the economy-wide analysis and discussed in Appendix B are still far below the projected benefits of the proposed rules.

Table 7-1 Monetized Benefits, Costs, and Net Benefits of the Three Illustrative Scenarios in 2028 (billion 2019 dollars) [a,b]

	Proposal			Less Stringent			More Stringent		
Climate Benefits [c]		0.60			0.51			0.029	
$PM_{2.5}$ and O_3-related Health Benefits [d]	0.68	and	1.6	0.49	and	1.2	-0.051	and	-0.42
Total Benefits [e]	1.3	and	2.2	1.0	and	1.7	-0.022	and	-0.39
Compliance Costs		-0.21			-0.19			-0.067	
Net Benefits	1.5	and	2.4	1.2	and	1.9	0.045	and	-0.32

[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] Climate benefits in this table are based on estimates of the SC-CO_2 at a 3 percent discount rate.
[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 3 percent.
[e] Several categories of benefits remain unmonetized and are thus not reflected in the table. Non-monetized benefits include important climate, health, welfare, and water quality benefits.

Table 7-2 Monetized Benefits, Costs, and Net Benefits of the Three Illustrative Scenarios in 2030 (billion 2019 dollars) [a,b]

	Proposal			Less Stringent			More Stringent		
Climate Benefits [c]		5.4			5.0			6.5	
$PM_{2.5}$ and O_3-related Health Benefits [d]	6.5	and	14	5.9	and	13	6.3	and	14
Total Benefits [e]	12	and	20	11	and	18	13	and	20
Compliance Costs		4.1			4.1			3.0	
Net Benefits	7.8	and	16	6.8	and	14	9.8	and	17

[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] Climate benefits in this table are based on estimates of the SC-CO_2 at a 3 percent discount rate.
[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 3 percent.
[e] Several categories of benefits remain unmonetized and are thus not reflected in the table. Non-monetized benefits include important climate, health, welfare, and water quality benefits.

Table 7-3 Monetized Benefits, Costs, and Net Benefits of the Three Illustrative Scenarios in 2035 (billion 2019 dollars) [a,b]

	Proposal			Less Stringent			More Stringent		
Climate Benefits [c]		2.5			2.4			2.8	
$PM_{2.5}$ and O_3-related Health Benefits [d]	2.2	and	4.7	1.9	and	3.9	2.2	and	4.6
Total Benefits [e]	4.6	and	7.1	4.2	and	6.3	5.0	and	7.4
Compliance Costs		0.28			0.23			0.20	
Net Benefits	4.4	and	6.8	4.0	and	6.0	4.8	and	7.2

[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] Climate benefits in this table are based on estimates of the SC-CO_2 at a 3 percent discount rate.
[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 3 percent.
[e] Several categories of benefits remain unmonetized and are thus not reflected in the table. Non-monetized benefits include important climate, health, welfare, and water quality benefits.

Table 7-4 Monetized Benefits, Costs, and Net Benefits of the Three Illustrative Scenarios in 2040 (billion 2019 dollars) [a,b]

	Proposal			Less Stringent			More Stringent		
Climate Benefits [c]		1.7			1.6			1.6	
$PM_{2.5}$ and O_3-related Health Benefits [d]	1.8	and	3.6	1.3	and	2.6	1.9	and	3.8
Total Benefits [e]	3.5	and	5.3	2.9	and	4.2	3.5	and	5.4
Compliance Costs		0.76			0.71			0.51	
Net Benefits	2.7	and	4.5	2.2	and	3.5	3.0	and	4.9

[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] Climate benefits in this table are based on estimates of the SC-CO_2 at a 3 percent discount rate.
[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 3 percent.
[e] Several categories of benefits remain unmonetized and are thus not reflected in the table. Non-monetized benefits include important climate, health, welfare, and water quality benefits.

Table 7-5 Illustrative Proposal Scenario: Present Values and Equivalent Annualized Values of Projected Monetized Compliance Costs, Benefits, and Net Benefits for 2024 to 2042 (billion 2019 dollars) [a,b]

	Climate Benefits	$PM_{2.5}$ and O_3-related Health Benefits		Compliance Costs	Net Benefits	
	3%	3%	7%		3%	7%
2024	-	-	-	0.012	-0.012	-0.012
2025	-	-	-	0.012	-0.012	-0.012
2026	-	-	-	0.013	-0.013	-0.013
2027	-	-	-	0.013	-0.013	-0.013
2028	0.60	1.6	1.4	-0.21	2.4	2.3
2029	5.4	14	12	4.1	15	14
2030	5.4	14	13	4.1	16	14
2031	5.5	14	13	4.1	16	14
2032	2.3	4.3	3.9	0.28	6.4	5.9
2033	2.4	4.4	4.0	0.28	6.5	6.1
2034	2.4	4.5	4.1	0.28	6.7	6.2
2035	2.5	4.7	4.2	0.28	6.8	6.4
2036	2.5	4.8	4.3	0.28	7.0	6.5
2037	2.5	4.9	4.4	0.28	7.1	6.6
2038	1.7	3.4	3.1	0.76	4.3	4.0
2039	1.7	3.5	3.1	0.76	4.4	4.1
2040	1.7	3.6	3.2	0.76	4.5	4.2
2041	1.7	3.6	3.3	0.76	4.6	4.2
2042	1.8	3.7	3.3	0.76	4.7	4.3

	Climate Benefits	$PM_{2.5}$ and O_3-related Health Benefits		Compliance Costs		Net Benefits	
	Discount Rate						
	3%	3%	7%	3%	7%	3%	7%
Present Value	**30**	**68**	**44**	**14**	**10**	**85**	**64**
Equivalent Annualized Value	**2.1**	**4.8**	**4.3**	**0.95**	**0.98**	**5.9**	**5.4**

[a] Annual values from 2024 to 2042 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] Climate benefits in this table are based on estimates of the SC-CO_2 at a 3 percent discount rate.
[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] Several categories of benefits remain unmonetized and are thus not reflected in the table. Non-monetized benefits include important climate, health, welfare, and water quality benefits.

Table 7-6 Illustrative Less Stringent Scenario: Present Values and Equivalent Annualized Values of Projected Monetized Compliance Costs, Benefits, and Net Benefits for 2024 to 2042 (billion 2019 dollars) [a,b]

	Climate Benefits	$PM_{2.5}$ and O_3-related Health Benefits		Compliance Costs	Net Benefits	
	3%	3%	7%		3%	7%
2024	-	-	-	0.012	-0.012	-0.012
2025	-	-	-	0.012	-0.012	-0.012
2026	-	-	-	0.013	-0.013	-0.013
2027	-	-	-	0.013	-0.013	-0.013
2028	0.51	1.2	1.0	-0.19	1.9	1.8
2029	5.0	13	11	4.1	13	12
2030	5.0	13	12	4.1	14	12
2031	5.1	13	12	4.1	14	13
2032	2.2	3.6	3.3	0.23	5.6	5.3
2033	2.3	3.7	3.4	0.23	5.8	5.4
2034	2.3	3.8	3.4	0.23	5.9	5.5
2035	2.4	3.9	3.5	0.23	6.0	5.6
2036	2.4	4.0	3.6	0.23	6.2	5.8
2037	2.4	4.1	3.7	0.23	6.3	5.9
2038	1.5	2.5	2.2	0.71	3.3	3.1
2039	1.6	2.5	2.3	0.71	3.4	3.1
2040	1.6	2.6	2.3	0.71	3.5	3.2
2041	1.6	2.6	2.4	0.71	3.5	3.3
2042	1.6	2.7	2.4	0.71	3.6	3.3

	Climate Benefits	$PM_{2.5}$ and O_3-related Health Benefits		Compliance Costs		Net Benefits	
	Discount Rate						
	3%	3%	7%	3%	7%	3%	7%
Present Value	**28**	**58**	**38**	**13**	**10**	**73**	**56**
Equivalent Annualized Value	**2.0**	**4.1**	**3.7**	**0.93**	**0.96**	**5.1**	**4.7**

[a] Annual values from 2024 to 2042 are not discounted. PV and EAV estimates discounted to 2024. Values have been rounded to two significant figures. Rows may not appear to add correctly due to rounding.
[b] Climate benefits in this table are based on estimates of the SC-CO_2 at a 3 percent discount rate.
[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] Several categories of benefits remain unmonetized and are thus not reflected in the table. Non-monetized benefits include important climate, health, welfare, and water quality benefits.

Table 7-7 Illustrative More Stringent Scenario: Present Values and Equivalent Annualized Values of Projected Monetized Compliance Costs, Benefits, and Net Benefits for 2024 to 2042 (billion 2019 dollars) [a,b]

	Climate Benefits	$PM_{2.5}$ and O_3-related Health Benefits		Compliance Costs	Net Benefits	
	3%	3%	7%		3%	7%
2024	-	-	-	0.012	-0.012	-0.012
2025	-	-	-	0.012	-0.012	-0.012
2026	-	-	-	0.013	-0.013	-0.013
2027	-	-	-	0.013	-0.013	-0.013
2028	0.029	-0.42	-0.37	-0.067	-0.32	-0.28
2029	6.4	13	12	3.0	17	15
2030	6.5	14	12	3.0	17	16
2031	6.6	14	12	3.0	17	16
2032	2.6	4.3	3.8	0.20	6.7	6.3
2033	2.7	4.4	3.9	0.20	6.9	6.4
2034	2.7	4.5	4.0	0.20	7.0	6.6
2035	2.8	4.6	4.1	0.20	7.2	6.7
2036	2.8	4.7	4.2	0.20	7.3	6.9
2037	2.9	4.5	4.1	0.20	7.2	6.8
2038	1.6	3.6	3.3	0.51	4.7	4.4
2039	1.6	3.7	3.3	0.51	4.8	4.4
2040	1.6	3.8	3.4	0.51	4.9	4.5
2041	1.7	3.9	3.5	0.51	5.0	4.6
2042	1.7	3.9	3.5	0.51	5.1	4.7

	Climate Benefits	$PM_{2.5}$ and O_3-related Health Benefits		Compliance Costs		Net Benefits	
	Discount Rate						
	3%	3%	7%	3%	7%	3%	7%
Present Value	**34**	**65**	**42**	**10**	**7.5**	**89**	**68**
Equivalent Annualized Value	**2.4**	**4.6**	**4.0**	**0.70**	**0.73**	**6.2**	**5.7**

Annual values from 2024 to 2042 are not discounted. PV and EAV estimates discounted to 2024. Values have been rounded to two significant figures. Rows may not appear to add correctly due to rounding.

[b] Climate benefits in this table are based on estimates of the SC-CO_2 at a 3 percent discount rate.

[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] Several categories of benefits remain unmonetized and are thus not reflected in the table. Non-monetized benefits include important climate, health, welfare, and water quality benefits.

8 IMPACTS OF PROPOSED 111(D) STANDARDS ON EXISTING NATURAL GAS-FIRED EGUS AND THIRD PHASE OF PROPOSED 111(B) STANDARDS ON NEW NATURAL GAS-FIRED EGUS

8.1 Introduction

The existing source performance standards modeled using IPM did not include proposed requirements on existing natural gas-fired combined cycle (NGCC) units as summarized in Table 8-1 below. To estimate the impact of these proposed requirements, EPA performed a spreadsheet-based analysis using the model output of each of the illustrative scenarios described earlier in the RIA to produce a range of possible outcomes as outlined in this section of the RIA.[159] This analysis therefore does not include any additional IPM modeling.

Table 8-1 GHG Mitigation Measures for Existing NGCC Units under the Illustrative Proposal, More Stringent and Less Stringent Scenarios

Affected EGUs	GHG Mitigation Measure	GHG Mitigation Measure
Natural Gas fired Combined Cycle Units > 300 MW and operating > 50% capacity factor in run year 2035 with online year of 2025 or earlier	Co-fire 30% by volume hydrogen in run year 2035, and 96% by volume hydrogen in run year 2040 onwards	CCS with 90 percent capture of CO_2, starting in run year 2035

The new source performance standards modeled using IPM also did not include additional requirements on new NGCC units —specifically, the proposed requirements for new base load combustion turbines in the hydrogen co-firing subcategory to comply with a third phase standard based on co-firing 96 percent low-GHG hydrogen by 2038— as summarized in Table 8-2. To estimate the impact of these proposed requirements, EPA performed a spreadsheet-based analysis using the model output of each of the illustrative scenarios to produce a range of possible outcomes as outlined in this section of the RIA.[160] As is the case for the analysis of existing natural gas-fired combined cycle units, this analysis also does not include any additional IPM modeling.

[159] The spreadsheet analysis for each of the scenarios is included in the docket for this rulemaking.
[160] The spreadsheet analysis for each of the scenarios is included in the docket for this rulemaking.

Table 8-2 GHG Mitigation Measures for New NGCC Units under the Illustrative Proposal, More Stringent and Less Stringent Scenarios

Affected EGUs	GHG Mitigation Measure
Natural Gas Combined Cycle Units with online year after 2025 that operate at > 50% capacity factor	Co-fire 96% by volume hydrogen in run year 2040 onwards or install CCS

8.2 Methodology

To estimate the regulatory impacts of the proposed requirements for existing and new NGCC units described in the previous section, EPA evaluated the impacts from the change in the existing source standard and new source standard separately. The approach to these analyses is outlined below.

8.2.1 111(d) Standards on Existing Natural Gas-Fired EGUs

To estimate the impact of the additional existing source standards, EPA relied on the IPM outputs of the illustrative proposal and less and more stringent illustrative scenarios as the baseline to estimate the impacts of the additional existing source standards for NGCC units using the spreadsheet-based approach. Hence this analysis included no additional IPM modeling. Units that would be subject to these requirements were identified by selecting model plants with average unit size greater than 300 MW that are projected to operate at greater than 50 percent capacity factor in the 2035 run year. Of these model plants, those that were projected to operate at higher capacity factors in 2035, 2040 and 2045 were assumed to install CCS rather than finding an alternative compliance pathway given plant economics.[161] EPA used different capacity factor cutoffs to construct a range of units assumed to install CCS, with the "low" end reflecting fewer CCS installations and the "high" end reflecting more CCS installations. Note EPA did not analyze the impacts of hydrogen co-firing as a compliance measure within this subcategory. All other model plants within this category were assumed to reduce utilization to 50 percent and, therefore, were not assumed to install CCS. 80 percent of the reduced dispatch as a result of

[161] To construct a range of selected units, EPA assumed model plants > 300 MW average unit size that operated at or above 80 percent in 2035, 2040 and 2045 formed one end of the range, and model plants > 300 MW average unit size that operated at or above 85 percent, 70 percent, 65 percent in 2035, 2040 and 2045 formed the other end of the range.

reduced utilization and capacity de-rates at units installing CCS were replaced by assuming increasing generation at existing NGCC units that are not subject to the requirements (i.e., model plants that operate at less than 50 percent capacity factor), while the remaining 20 percent of the generation was replaced by incremental non-emitting generation. The amount of capacity assumed to adopt CCS and the resource mix assumed to fill in dispatch as a result of reduced utilization were both based on EPA expert judgment based on trends in prior IPM runs.

EPA used projected generation weighted average national CO_2 emission rates from each of the sets of units described above in each run year to estimate the CO_2 emission impacts resulting from these changes. EPA used the generation weighted average national projected fuel and variable operating costs from model plants that are assumed to reduce dispatch and those that assumed to increase dispatch to calculate the cost of shifts in generation to lower utilized existing NGCC model plants. EPA used the average generation weighted national projected costs for wind and solar additions in each run year to calculate the cost of incremental non-emitting generation assumed within the analysis. Finally, EPA used cost and performance assumptions consistent with the IPM post-IRA 2023 reference case to calculate the costs and emissions reductions associated with CCS installations at existing NGCC units.[162]

8.2.2 Third Phase of 111(b) Standards on New Natural Gas-Fired EGUs

To estimate the impact of the additional new source standards, EPA relied on the IPM outputs of the illustrative proposal and less and more stringent illustrative scenarios to determine the baseline for the spreadsheet-based analysis. Therefore, no incremental IPM modeling was performed for this analysis. We identified new NGCC model plants that are projected to operate at greater than 50 percent capacity factor and are projected to co-fire less than 96 percent hydrogen by volume in run year 2040. Of these model plants, the largest 20 percent of model plants and the largest 40 percent of model plants were assumed to increase hydrogen co-firing to form the basis of the low and high ends of the range showed in this section.

EPA did not analyze the impacts of CCS as a compliance measure within this subcategory. All other model plants within this category were assumed to reduce utilization to 50

[162] Available at: https://www.epa.gov/power-sector-modeling/post-ira-2022-reference-case

percent and therefore did not increase hydrogen co-fire share. 80 percent of the reduced dispatch as a result of reduced utilization were replaced by assuming increasing generation at existing NGCC units that are not subject to the requirements (i.e., model plants that operate at less than 50 percent capacity factor), while the remaining 20 percent of the generation was replaced by incremental non-emitting generation. EPA used projected generation weighted average national CO_2 emission rates from each of the sets of units described above in each run year to track the CO_2 emission impacts resulting from these changes. EPA used the generation weighted average national projected fuel and variable operating costs from model plants that are assumed to reduce dispatch and those that assumed to increase dispatch to calculate the cost of shifts in generation to lower utilized existing NGCC model plants. We used the generation weighted average national projected costs for wind and solar additions in each run year to calculate the cost of incremental non-emitting generation assumed within the analysis. Finally, we assumed a \$0.5/kg delivered hydrogen price to calculate the costs of increased hydrogen consumption, consistent with the hydrogen price assumed in the modeling when the second phase is active. For reference in the results that follow, these estimates are referred to as “low” and “high” based on the total amount of associated emissions reductions.

8.3 Estimated Regulatory Impacts

Using the approach outlined above, EPA estimate the impacts on power sector CO_2 emissions, costs, generation, and incremental hydrogen demand for the proposed requirements on existing and new NGCC units. We note the analysis approach used in this section to estimate emissions impacts of the proposed 111(d) standards on existing natural gas-fired EGUs and the third phase of proposed 111(b) standards on new natural gas-fired EGUs does not permit the estimation of changes in emissions of non-CO_2 pollutants.

Because this additional analysis used the IPM outputs from the illustrative scenarios as its baseline, these results do not capture the potential for interactive effects between the additional measures and the IPM-modeled measures (e.g., the potential that establishing 111(d) requirements for existing natural gas-fired EGUs could affect the compliance approaches undertaken by other EGUs or lead to different shifts in the overall generation mix than those reflected in the IPM outputs).

8.3.1 Emissions Reduction Assessment

8.3.1.1 111(d) Standards on Existing Natural Gas-Fired EGUs

Based on the analysis outlined above, EPA estimated the change in CO_2 emissions from the additional measures selected to the outcomes under each of the illustrative scenarios discussed elsewhere in this RIA (the IPM-modeled aspects of the regulatory approach to existing fossil-fuel fired steam generating units and new and reconstructed stationary combustion turbines). These results are summarized in Table 8-3 below, showing results for low and high ends of a range based on different assumptions in how many model existing plants are assumed to install CCS.

Table 8-3 Estimated Changes in Power Sector Emissions from Existing Source Standard under the Three Illustrative Scenarios

Annual CO_2 (million metric tons)	Proposal		Less Stringent		More Stringent	
	Low	High	Low	High	Low	High
2028	0	0	0	0	0	0
2030	0	0	0	0	0	0
2035	-20	-37	-20	-37	-20	-37
2040	-19	-37	-19	-37	-19	-37

8.3.1.2 Third Phase of 111(b) Standards on New Natural Gas-Fired EGUs

Based on the analysis outlined above, EPA estimated the change in emissions from the measures selected to the outcomes under each of the illustrative scenarios discussed elsewhere in this RIA. These results are summarized in the Table 8-4 below, showing results for low and high ends of a range based on different assumptions in how many model new plants are projected to increase hydrogen co-firing.

Table 8-4 Estimated Changes in Power Sector Emissions from New Source Standard under the Three Illustrative Scenarios

Annual CO_2 (million metric tons)	Proposal		Less Stringent		More Stringent	
	Low	High	Low	High	Low	High
2028	0	0	0	0	0	0
2030	0	0	0	0	0	0
2035	0	0	0	0	0	0
2040	-0.22	-2.5	-0.20	-2.5	-2.2	-4.2

8.3.2 Compliance Cost Assessment

8.3.2.1 111(d) Standards on Existing Natural Gas-Fired EGUs

Based on the analysis outlined above, EPA estimated the change in costs from the measures selected to the outcomes under each of the illustrative scenarios discussed elsewhere in this RIA. These results are summarized in Table 8-5.

Table 8-5 Estimated Changes in Power Sector Costs from Existing Source Standard under the Three Illustrative Scenarios (billion 2019 dollars)

	Proposal		Less Stringent		More Stringent	
	Low	High	Low	High	Low	High
2028	0	0	0	0	0	0
2030	0	0	0	0	0	0
2035	0.76	1.3	0.76	1.3	0.76	1.3
2040	0.68	1.2	0.68	1.2	0.68	1.2

8.3.2.2 Third Phase of 111(b) Standards on New Natural Gas-Fired EGUs

Based on the analysis outlined above, EPA estimated the change in costs from the measures selected to the outcomes under each of the illustrative scenarios discussed elsewhere in this RIA. These results are summarized in Table 8-6.

Table 8-6 Estimated Changes in Power Sector Costs from New Source Standard under the Three Illustrative Scenarios (billion 2019 dollars)

	Proposal		Less Stringent		More Stringent	
	Low	**High**	**Low**	**High**	**Low**	**High**
2028	0	0	0	0	0	0
2030	0	0	0	0	0	0
2035	0	0	0	0	0	0
2040	0.064	0.21	0.064	0.21	0.24	0.37

EPA did not conduct IPM modeling in order to evaluate the impacts of the requirements on existing natural gas-fired EGUs and the third phase of the requirements on new natural gas-fired EGUs, relying instead on a spreadsheet-based analysis as outlined in Section 8 of the RIA. When relying on IPM projections, EPA estimates retail rate impacts using the methodology outlined in the Retail Price Model.[163] The spreadsheet-based approach described in section 8 does not provide the necessary inputs to populate the RPM; however, given the trends in total compliance costs, EPA expects that retail rates are likely to increase at similar levels to those estimated under the analysis provided in Section 3.6.3 of this RIA. In particular, total compliance costs are projected to range between 0.8 and 4 billion 2019$ between 2030 and 2040 under the modeled proposal, and retail rates are projected to rise between 0.1 percent to 2 percent over the 2030 and 2040 period. In comparison, estimated total compliance costs range between 0.7 and 1.4 billion 2019$ between 2030 and 2040 as a result of requirements on existing natural gas-fired EGUs and the third phase of the requirements on new natural gas-fired EGUs under the spreadsheet-based approach outlined in Section 8.

8.3.3 Generation Mix and Compliance Outcomes

8.3.3.1 111(d) Standards on Existing Natural Gas-Fired EGUs

Based on the analysis outlined above, EPA estimated the change in generation from the measures selected to the outcomes under each of the illustrative scenarios discussed elsewhere in this RIA. These results are summarized in Table 8-7. Because this additional analysis used the IPM outputs from the illustrative scenarios as its baseline, these results do not capture the potential for interactive effects between the additional measures and the IPM-modeled measures

[163] Available at: https://www.epa.gov/power-sector-modeling/retail-price-model

(e.g., the potential that establishing 111(d) requirements for existing natural gas-fired EGUs could affect the compliance approaches undertaken by other EGUs or lead to different shifts in the overall generation mix than those reflected in the IPM outputs).

Table 8-7 Estimated Changes in Power Sector Generation from Existing Source Standard under the Three Illustrative Scenarios

Proposal	**Low**				**High**			
Change in Generation (TWh)	2028	2030	2035	2040	2028	2030	2035	2040
EGUs assumed to Install CCS	0	0	-11.7	-11.7	0	0	-23.4	-23.4
EGUs assumed to reduce dispatch	0	0	-80.3	-67.1	0	0	-54.2	-41.0
Reallocated by each category:								
Existing CC	0	0	73.6	63.1	0	0	62.0	51.5
Zero-emitting	0	0	18.4	15.8	0	0	15.5	12.9
Total	0	0	0.0	0.0	0	0	0.0	0.0

Less Stringent	**Low**				**High**			
Change in Generation (TWh)	2028	2030	2035	2040	2028	2030	2035	2040
EGUs assumed to Install CCS	0	0	-11.7	-11.7	0	0	-23.4	-23.4
EGUs assumed to reduce dispatch	0	0	-81.5	-67.2	0	0	-55.4	-41.1
Reallocated by each category:								
Existing CC	0	0	74.6	63.2	0	0	63.0	51.6
Zero-emitting	0	0	18.6	15.8	0	0	15.7	12.9
Total	0	0	0.0	0.0	0	0	0.0	0.0

More Stringent	Low				High			
Change in Generation (TWh)	2028	2030	2035	2040	2028	2030	2035	2040
EGUs assumed to Install CCS	0	0	-11.7	-11.7	0	0	-23.4	-23.4
EGUs assumed to reduce dispatch	0	0	-79.7	-67.5	0	0	-53.6	-41.4
Reallocated by each category:								
Existing CC	0	0	73.1	63.4	0	0	61.5	51.8
Zero-emitting	0	0	18.3	15.8	0	0	15.4	13.0
Total	0	0	0.0	0.0	0	0	0.0	0.0

Using the methodology outlined above, EPA estimated that 36.8 GW of existing NGCC capacity had an average modeled unit size of greater than 300 MW and was projected to operate at greater than 50 percent capacity factor in 2035 under the illustrative scenarios. Of these 36.8 GW, 8.6 GW to 17.3 GW were identified as more likely to install CCS rather than pursue an alternative compliance pathway based on high levels of utilization across the 2035, 2040 and

2045 run years, and related plant economics. Units installing CCS were assumed to maintain their capacity factors, but incurred an 18 percent capacity penalty, resulting in reduced dispatch. The remaining identified existing NGCC capacity was assumed to operate at 50 percent capacity factor. 80 percent of the reductions in generation were apportioned to existing NGCC units operating below 50 percent capacity factor and the remaining 20 percent were apportioned to incremental non-emitting resources. As shown in the table below, the decreases in generation from affected NGCC units are exactly offset by increases in replacement generation. Since existing NGCC units are projected to operate similarly across the three illustrative scenarios, the methodology used to determine potential impacts of the additional existing source requirements results in similar outcomes across the cases.

Using the methodology outlined above, EPA estimates a minimal impact on the total amount of accredited capacity as a result of the standards on existing combustion turbines. In particular, the analysis assumes no incremental retirements at existing NGCC units, and an installation of 8.6 GW to 17.3 GW of incremental CCS installations by 2035 under the illustrative scenarios. Since retrofit CCS installations are assumed to incur an 18 percent capacity penalty, this results in a total reduction in NGCC of 1.5 to 3.1 GW of accredited capacity nationwide. At the same time, the analysis assumes that an incremental 4.6 to 5.5 GW of zero-emitting capacity is added or maintained nationwide. To fully offset the reduction of accredited capacity in NGCC would require that the zero-emitting resources were able to contribute 33 percent of their total capacity to reserve in the low scenario and 56 percent in the high scenario.

To put the capacity totals into context, total US projected peak demand in 2035 is 886 GW, and there are 58 GW of retirements and 332 GW of capacity additions projected between the 2030 and 2035 model run years under the Proposal modeling.

Using the methodology outlined above, EPA estimates no impact on the total amount of accredited capacity as a result of the third phase requirement on new combustion turbines.

Using the methodology outlined above, EPA assumes a minimal change (less than one percent) in natural gas consumption and therefore on delivered natural gas prices.

8.3.3.2 Third Phase of 111(b) Standards on New Natural Gas-Fired EGUs

Based on the analysis outlined above, EPA estimated the change in generation from the measures selected to the outcomes under each of the illustrative scenarios discussed elsewhere in this RIA. These results are summarized in Table 8-8 below.

Under the modeled illustrative scenarios, IPM projected 25.7 GW of new NGCC additions under the proposal, 25.3 GW of new NGCC additions under the less stringent scenario and 22.8 GW of new NGCC additions under the more stringent scenario. Of these projected builds, 6.4 GW were projected to co-fire hydrogen under the proposal and less stringent scenario, and 13.6 GW were projected to co-fire hydrogen under the more stringent scenario. Using the methodology outlined above, EPA estimated that in 2040, 0.4 – 1.5 GW of capacity increased hydrogen co-fire blends to 96 percent by volume while the remaining capacity reduced dispatch to below 50 percent under the proposal and less stringent scenarios. EPA did not analyze the impacts of CCS as a compliance measure within this subcategory. EPA estimated that in 2040 1.6 to 2.7 GW of capacity increased hydrogen co-fire blends to 96 percent by volume and the remaining capacity reduced dispatch to below 50 percent capacity factor under the more stringent scenario. 80 percent of the reductions in generation were apportioned to existing NGCC units operating below 50 percent capacity factor and the remaining 20 percent apportioned to incremental non-emitting resources. As shown in the table below, the decreases in generation from affected new NGCC units is exactly offset by increases in replacement generation. Since a larger amount of new NGCC units are projected to co-fire hydrogen under the more stringent scenario, reductions are largest under that scenario. Since a similar amount new NGCC units are projected to co-fire hydrogen under the more and less stringent scenarios, reductions are similar under those scenarios.

Table 8-8 Estimated Changes in Power Sector Generation from New Source Standard under the Three Illustrative Scenarios

Proposal	Low				High			
Change in Generation (TWh)	2028	2030	2035	2040	2028	2030	2035	2040
EGUs assumed to increase co-fire share	0	0	0	0.0	0	0	0	0.0
EGUs assumed to reduce dispatch	0	0	0	-16.5	0	0	0	-13.0
Reallocated by each category:	0	0	0	0.0	0	0	0	0.0
Existing CC	0	0	0	13.2	0	0	0	10.4
Zero-emitting	0	0	0	3.3	0	0	0	2.6
Total	0	0	0	0.0	0	0	0	0.0

Less Stringent	Low				High			
Change in Generation (TWh)	2028	2030	2035	2040	2028	2030	2035	2040
EGUs assumed to increase co-fire share	0	0	0	0.0	0	0	0	0.0
EGUs assumed to reduce dispatch	0	0	0	-16.7	0	0	0	-13.1
Reallocated by each category:	0	0	0	0.0	0	0	0	0.0
Existing CC	0	0	0	13.4	0	0	0	10.5
Zero-emitting	0	0	0	3.3	0	0	0	2.6
Total	0	0	0	0.0	0	0	0	0.0

More Stringent	Low				High			
Change in Generation (TWh)	2028	2030	2035	2040	2028	2030	2035	2040
EGUs assumed to increase co-fire share	0	0	0	0.0	0	0	0	0.0
EGUs assumed to reduce dispatch	0	0	0	-29.9	0	0	0	-27.5
Reallocated by each category:	0	0	0	0.0	0	0	0	0.0
Existing CC	0	0	0	23.9	0	0	0	22.0
Zero-emitting	0	0	0	6.0	0	0	0	5.5
Total	0	0	0	0.0	0	0	0	0.0

Table 8-9 below outlines the incremental hydrogen demand that would be required to fuel the higher co-firing levels assumed in the analysis of the new source standards. For context, the analysis of the requirements on existing coal fired EGUs and the two phase NSPS (as outlined in Section 3) projected Hydrogen consumption varied between 2.5 to 2.9 million metric tons in 2040. As outlined in Section 3, hydrogen is an exogenous input to the model, represented as a fuel that is available at affected sources at a delivered cost of $1/kg under the baseline, and at a delivered cost of $0.5/kg in years when the second phase of the proposed NSPS is assumed to be active. These costs are inclusive of $3/kg subsidies under the IRA. 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. Similarly, the spreadsheet-based analysis does not estimate any upstream emissions associated with hydrogen production, nor any incremental electricity demand associated with its production.

Table 8-9 Estimated Changes in Power Sector Hydrogen Demand from New Source Standard under the Three Illustrative Scenarios

Hydrogen Demand (MMT)	Proposal		Less Stringent		More Stringent	
	Low	High	Low	High	Low	High
2028	0	0	0	0	0	0
2030	0	0	0	0	0	0
2035	0	0	0	0	0	0
2040	0.00	0.32	0.00	0.33	0.25	0.53

8.4 Climate Benefits Analysis

Using the methods described in Section 4.2, we estimate the social benefits of CO_2 reductions expected to occur as a result of the projected CO_2 reductions presented in Section 8.3.1 using estimates of the social cost of greenhouse gases (SC-GHG), specifically using the social cost of carbon (SC-CO_2). As mentioned earlier, the analysis approach used in this section to estimate emissions impacts of the proposed 111(d) standards on existing natural gas-fired EGUs and the third phase of proposed 111(b) standards on new natural gas-fired EGUs does not permit the estimation of changes in emissions of non-CO_2 pollutants. Consequently, the benefits analysis in this section is limited to an assessment of the projected climate benefits arising from the proposed provisions analyzed in this section.

8.4.1 111(d) Standards on Existing Natural Gas-Fired EGUs

Based on the analysis outlined above this section, EPA estimated the change in CO_2 emissions in 2028, 2030, 2035, and 2040 from the measures selected to the outcomes under each of the illustrative scenarios described elsewhere in this RIA (see Table 8-3). To obtain annual estimates of CO_2 reductions from 2028 to 2042, we mapped the emissions reductions in 2030 as presented in Table 8-3 to calendar years 2029 to 2031, the emissions reductions in 2035 to calendar years 2032 to 2037, and the emissions reductions in 2040 to calendar years 2038 to 2042. The resulting estimated annual changes in GHG emissions are shown in Table 8-10 below.

Table 8-10 Annual CO_2 Emissions Reductions (million metric tons) for the 111(d) Standards on Existing Natural Gas-Fired EGUs Illustrative Scenarios from 2028 through 2042

	Proposal Scenario		Less Stringent Scenario		More Stringent Scenario	
	Low	**High**	**Low**	**High**	**Low**	**High**
2028	-	-	-	-	-	-
2029	-	-	-	-	-	-
2030	-	-	-	-	-	-
2031	-	-	-	-	-	-
2032	20	37	20	37	20	37
2033	20	37	20	37	20	37
2034	20	37	20	37	20	37
2035	20	37	20	37	20	37
2036	20	37	20	37	20	37
2037	20	37	20	37	20	37
2038	19	37	19	37	19	37
2039	19	37	19	37	19	37
2040	19	37	19	37	19	37
2041	19	37	19	37	19	37
2042	19	37	19	37	19	37
Total	214	407	215	407	214	407

Table 8-11 through Table 8-13 show the estimated monetary value of the CO_2 emissions reductions estimated to occur over the 2028 to 2042 period for the illustrative scenarios. EPA estimated the dollar value of the GHG-related effects for each analysis year between 2028 and 2042 by applying the SC-CO_2 estimates presented in Table 4-1 to the estimated changes in GHG emissions in the corresponding year as shown above in Table 8-10. EPA then calculated the present value (PV) and equivalent annualized value (EAV) of benefits from the perspective of 2024 by discounting each year-specific value to the year 2024 using the same discount rate used to calculate the SC-CO_2. See Table 8-11, Table 8-12, and Table 8-13 for the climate benefit estimates for the proposal and less and more stringent illustrative scenarios associated with the proposed standards on existing natural gas-fired EGUs, respectively.

Table 8-11 Range of Benefits of Reduced CO_2 Emissions from the 111(d) Standards on Existing Natural Gas-Fired EGUs Illustrative Proposal Scenario, 2028 to 2042 (millions of 2019 dollars)[a]

Emissions Year	SC-CO_2 Discount Rate and Statistic (millions 2019 dollars)			
	5% Average	**3% Average**	**2.5% Average**	**3% 95th Percentile**
2028	-	-	-	-
2029	-	-	-	-
2030	-	-	-	-
2031	-	-	-	-
2032	$400-750	$1,200-2,300	$1,800-3,400	$3,700-7,100
2033	$410-770	$1,300-2,400	$1,800-3,400	$3,800-7,300
2034	$420-790	$1,300-2,400	$1,800-3,500	$3,900-7,400
2035	$430-820	$1,300-2,500	$1,900-3,500	$4,000-7,500
2036	$440-840	$1,300-2,500	$1,900-3,600	$4,000-7,700
2037	$450-860	$1,300-2,600	$1,900-3,600	$4,100-7,800
2038	$460-880	$1,400-2,600	$1,900-3,700	$4,200-7,900
2039	$470-900	$1,400-2,600	$1,900-3,700	$4,200-8,100
2040	$480-920	$1,400-2,700	$2,000-3,800	$4,300-8,200
2041	$490-940	$1,400-2,700	$2,000-3,800	$4,400-8,300
2042	$510-970	$1,400-2,800	$2,000-3,900	$4,400-8,500
PV	$2,600-5,000	$10,000-19,000	$15,000-29,000	$31,000-58,000
EAV	$220-410	$700-1,300	$1000-1,900	$2,100-4,100

[a] Climate benefits are based on changes (reductions) in CO_2 emissions and are calculated using four different estimates of the SC-CO_2 (model average at 2.5 percent, 3 percent, and 5 percent discount rates; and 95th percentile at 3 percent discount rate). The IWG emphasized the importance and value of considering the benefits calculated using all four estimates. As discussed in the Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990 (IWG, 2021), a consideration of climate benefits calculated using discount rates below 3 percent, including 2 percent and lower, is also warranted when discounting intergenerational impacts.

Table 8-12 Range of Benefits of Reduced CO_2 Emissions from the 111(d) Standards on Existing Natural Gas-Fired EGUs Illustrative Less Stringent Scenario, 2028 to 2042 (millions of 2019 dollars)[a]

Emissions Year	SC-CO_2 Discount Rate and Statistic (millions 2019 dollars)			
	5% Average	**3% Average**	**2.5% Average**	**3% 95th Percentile**
2028	-	-	-	-
2029	-	-	-	-
2030	-	-	-	-
2031	-	-	-	-
2032	$400-750	$1,200-2,300	$1,800-3,400	$3,800-7,100
2033	$410-770	$1,300-2,400	$1,800-3,400	$3,800-7,300
2034	$420-800	$1,300-2,400	$1,800-3,500	$3,900-7,400
2035	$430-820	$1,300-2,500	$1,900-3,500	$4,000-7,500
2036	$440-840	$1,300-2,500	$1,900-3,600	$4,100-7,700
2037	$450-860	$1,400-2,600	$1,900-3,600	$4,100-7,800
2038	$460-880	$1,400-2,600	$1,900-3,700	$4,200-7,900
2039	$470-900	$1,400-2,600	$1,900-3,700	$4,200-8,100
2040	$480-920	$1,400-2,700	$2,000-3,800	$4,300-8,200
2041	$500-940	$1,400-2,700	$2,000-3,800	$4,400-8,300
2042	$510-970	$1,400-2,800	$2,000-3,900	$4,400-8,500
PV	$2,600-5,000	$10,000-19,000	$15,000-29,000	$31,000-58,000
EAV	$220-410	$700-1,300	$1,000-1,900	$2,100-4,100

[a] Climate benefits are based on changes (reductions) in CO_2 emissions and are calculated using four different estimates of the SC-CO_2 (model average at 2.5 percent, 3 percent, and 5 percent discount rates; and 95th percentile at 3 percent discount rate). The IWG emphasized the importance and value of considering the benefits calculated using all four estimates. As discussed in the Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990 (IWG, 2021), a consideration of climate benefits calculated using discount rates below 3 percent, including 2 percent and lower, is also warranted when discounting intergenerational impacts.

Table 8-13 Range of Benefits of Reduced CO_2 Emissions from the 111(d) Standards on Existing Natural Gas-Fired EGUs Illustrative More Stringent Scenario, 2028 to 2042 (millions of 2019 dollars)[a]

Emissions Year	SC-CO_2 Discount Rate and Statistic (millions 2019 dollars)			
	5% Average	**3% Average**	**2.5% Average**	**3% 95th Percentile**
2028	-	-	-	-
2029	-	-	-	-
2030	-	-	-	-
2031	-	-	-	-
2032	$400-750	$1,200-2,300	$1,800-3,400	$3,800-7,100
2033	$410-770	$1,300-2,400	$1,800-3,400	$3,800-7,300
2034	$420-790	$1,300-2,400	$1,800-3,500	$3,900-7,400
2035	$430-820	$1,300-2,500	$1,900-3,500	$4,000-7,500
2036	$440-840	$1,300-2,500	$1,900-3,600	$4,100-7,700
2037	$450-860	$1,300-2,600	$1,900-3,600	$4,100-7,800
2038	$460-880	$1,400-2,600	$1,900-3,700	$4,200-7,900
2039	$470-900	$1,400-2,600	$2,000-3,700	$4,300-8,100
2040	$480-920	$1,400-2,700	$2,000-3,800	$4,300-8,200
2041	$500-940	$1,400-2,700	$2,000-3,800	$4,400-8,300
2042	$510-970	$1,500-2,800	$2,000-3,900	$4,500-8,500
PV	$2,600-5,000	$10,000-19,000	$15,000-29,000	$31,000-58,000
EAV	$220-410	$700-1,300	$1,000-1,900	$2,200-4,100

[a] Climate benefits are based on changes (reductions) in CO_2 emissions and are calculated using four different estimates of the SC-CO_2 (model average at 2.5 percent, 3 percent, and 5 percent discount rates; and 95th percentile at 3 percent discount rate). The IWG emphasized the importance and value of considering the benefits calculated using all four estimates. As discussed in the Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990 (IWG, 2021), a consideration of climate benefits calculated using discount rates below 3 percent, including 2 percent and lower, is also warranted when discounting intergenerational impacts.

8.4.2 Third Phase of 111(b) Standards on New Natural Gas-Fired EGUs

Based on the analysis outlined above, EPA estimated the change in emissions from the measures selected to the outcomes under each of the illustrative scenarios for the third phase of the 111(b) standards on new natural gas-fired EGUs. Using the same model year to calendar year mapping described in the previous section, the estimated annual change in CO_2 emissions are shown in Table 8-14 below.

Table 8-14 Annual CO_2 Emissions Reductions (million metric tons) for the 111(b) Standards on New Natural Gas-Fired EGUs Illustrative Scenarios from 2028 through 2042

	Proposal Scenario		Less Stringent Scenario		More Stringent Scenario	
	Low	**High**	**Low**	**High**	**Low**	**High**
2028	-	-	-	-	-	-
2029	-	-	-	-	-	-
2030	-	-	-	-	-	-
2031	-	-	-	-	-	-
2032	-	-	-	-	-	-
2033	-	-	-	-	-	-
2034	-	-	-	-	-	-
2035	-	-	-	-	-	-
2036	-	-	-	-	-	-
2037	-	-	-	-	-	-
2038	0	2	2	4	0	3
2039	0	2	2	4	0	3
2040	0	2	2	4	0	3
2041	0	2	2	4	0	3
2042	0	2	2	4	0	3
Total	1	12	11	21	1	13

Table 8-15 through Table 8-17 show the estimated monetary value of the estimated changes in CO_2 emissions expected to occur over 2028 through 2042 for the illustrative scenarios. EPA estimated the dollar value of the GHG-related effects for each analysis year between 2028 and 2042 by applying the SC-GHG estimates presented in Table 4-1 to the estimated changes in GHG emissions in the corresponding year as shown above in Table 8-14. EPA then calculated the PV and EAV of benefits from the perspective of 2024 by discounting each year-specific value to the year 2024 using the same discount rate used to calculate the SC-GHG.

Table 8-15 Range of Benefits of Reduced CO_2 Emissions from the 111(b) Standards on New Natural Gas-Fired EGUs Illustrative Proposal Scenario, 2028 to 2042 (millions of 2019 dollars)[a]

	SC-CO_2 Discount Rate and Statistic (millions 2019 dollars)			
Emissions Year	**5% Average**	**3% Average**	**2.5% Average**	**3% 95th Percentile**
2028	-	-	-	-
2029	-	-	-	-
2030	-	-	-	-
2031	-	-	-	-
2032	-	-	-	-
2033	-	-	-	-
2034	-	-	-	-
2035	-	-	-	-
2036	-	-	-	-
2037	-	-	-	-
2038	$5.2-59	$15-170	$22-250	$47-530
2039	$5.3-60	$15-180	$22-250	$47-540
2040	$5.4-62	$16-180	$22-250	$48-550
2041	$5.5-63	$16-180	$22-260	$49-560
2042	$5.7-65	$16-180	$23-260	$50-570
PV	$12-140	$49-560	$74-850	$150-1,700
EAV	$1-12	$3.4-39	$5-57	$10-120

[a] Climate benefits are based on changes (reductions) in CO_2 emissions and are calculated using four different estimates of the SC-CO_2 (model average at 2.5 percent, 3 percent, and 5 percent discount rates; and 95th percentile at 3 percent discount rate). The IWG emphasized the importance and value of considering the benefits calculated using all four estimates. As discussed in the Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990 (IWG, 2021), a consideration of climate benefits calculated using discount rates below 3 percent, including 2 percent and lower, is also warranted when discounting intergenerational impacts.

Table 8-16 Range of Benefits of Reduced CO_2 Emissions from the 111(b) Standards on New Natural Gas-Fired EGUs Illustrative Less Stringent Scenario, 2028 to 2042 (millions of 2019 dollars)[a]

	SC-CO_2 Discount Rate and Statistic (millions 2019 dollars)			
Emissions Year	**5% Average**	**3% Average**	**2.5% Average**	**3% 95th Percentile**
2028	-	-	-	-
2029	-	-	-	-
2030	-	-	-	-
2031	-	-	-	-
2032	-	-	-	-
2033	-	-	-	-
2034	-	-	-	-
2035	-	-	-	-
2036	-	-	-	-
2037	-	-	-	-
2038	$4.7-59	$14-180	$19-250	$42-540
2039	$4.8-61	$14-180	$20-250	$43-550
2040	$4.9-62	$14-180	$20-260	$44-560
2041	$5-64	$14-180	$20-260	$44-570
2042	$5.1-66	$15-190	$20-260	$45-570
PV	$11-140	$44-560	$67-860	$140-1,700
EAV	$0.93-12	$3.1-39	$4.5-57	$9.5-120

[a] Climate benefits are based on changes (reductions) in CO_2 emissions and are calculated using four different estimates of the SC-CO_2 (model average at 2.5 percent, 3 percent, and 5 percent discount rates; and 95th percentile at 3 percent discount rate). The IWG emphasized the importance and value of considering the benefits calculated using all four estimates. As discussed in the Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990 (IWG, 2021), a consideration of climate benefits calculated using discount rates below 3 percent, including 2 percent and lower, is also warranted when discounting intergenerational impacts.

Table 8-17 Range of Benefits of Reduced CO_2 Emissions from the 111(b) Standards on New Natural Gas-Fired EGUs Illustrative More Stringent Scenario, 2028 to 2042 (millions of 2019 dollars)[a]

Emissions Year	SC-CO_2 Discount Rate and Statistic (millions 2019 dollars)			
	5% Average	3% Average	2.5% Average	3% 95th Percentile
2028	-	-	-	-
2029	-	-	-	-
2030	-	-	-	-
2031	-	-	-	-
2032	-	-	-	-
2033	-	-	-	-
2034	-	-	-	-
2035	-	-	-	-
2036	-	-	-	-
2037	-	-	-	-
2038	$52-99	$150-290	$220-420	$470-900
2039	$54-100	$160-300	$220-420	$480-920
2040	$55-100	$160-300	$230-430	$490-930
2041	$56-110	$160-310	$230-430	$500-950
2042	$58-110	$160-310	$230-440	$510-960
PV	$130-240	$500-940	$760-1,400	$1,500-2,900
EAV	$10-20	$35-66	$51-96	$110-200

[a] Climate benefits are based on changes (reductions) in CO_2 emissions and are calculated using four different estimates of the SC-CO_2 (model average at 2.5 percent, 3 percent, and 5 percent discount rates; and 95th percentile at 3 percent discount rate). The IWG emphasized the importance and value of considering the benefits calculated using all four estimates. As discussed in the Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990 (IWG, 2021), a consideration of climate benefits calculated using discount rates below 3 percent, including 2 percent and lower, is also warranted when discounting intergenerational impacts.

8.5 Present Values and Equivalent Annualized Values of Costs and Climate Benefits

This section presents the present value (PV) and equivalent annualized value (EAV) estimates of compliance costs and climate benefits based on the analysis above. All cost and benefit analysis in this section begins in 2028. Costs associated with monitoring, reporting, and recordkeeping (MR&R) are detailed in Section 3.3 and are included in the net benefit analysis in Section 7.[164]

[164] To limit duplication, MR&R costs are not included in the tables in this section.

EPA calculated the PV of costs and climate benefits for the years 2028 through 2042, using both a three percent and seven percent discount rate from the perspective of 2024. We also present the EAV, which represents a flow of constant annual values that, had they occurred in each year from 2024 to 2042, would yield a sum equivalent to the PV. The EAV represents the value of a typical cost or benefit for each year of the analysis, in contrast to the specific snapshot-year estimates reported earlier in this section. All dollars are in 2019 dollars. To implement the OMB Circular A-4 requirement for fulfilling E.O. 12866, we assess one less stringent and one more stringent illustrative scenario relative to the illustrative proposal scenario.

8.5.1 Compliance Costs

Table 8-18 and Table 8-19 present the estimated costs in PV and EAV terms for the three illustrative scenarios, discounted at three percent and seven percent, respectively. Estimates in the tables are presented as rounded values.

Table 8-18 Present Values and Equivalent Annualized Values of Estimated Compliance Costs of Three Illustrative Scenarios for 2028 to 2042, Calculated using 3 Percent Discount Rate (billion 2019 dollars)[a]

	111(d) for Existing Gas		111(b) for New Gas		Total Costs	
	Low	High	Low	High	Low	High
Proposal Scenario						
Present Value	5.5	9.3	0.20	0.65	5.7	10
Equivalent Annualized Value	0.38	0.65	0.014	0.045	0.40	0.70
Less Stringent Scenario						
Present Value	5.5	9.3	0.20	0.65	5.7	10
Equivalent Annualized Value	0.38	0.65	0.014	0.046	0.40	0.70
More Stringent Scenario						
Present Value	5.5	9.3	0.74	1.1	6.2	10
Equivalent Annualized Value	0.38	0.65	0.052	0.080	0.44	0.73

[a] 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.

Table 8-19 Present Values and Equivalent Annualized Values of Estimated Compliance Costs of Three Illustrative Scenarios for 2028 to 2042, Calculated using 7 Percent Discount Rate (billion 2019 dollars)[a]

	111(d) for Existing Gas		111(b) for New Gas		Total Costs	
	Low	**High**	**Low**	**High**	**Low**	**High**
Proposal Scenario						
Present Value	3.4	5.8	0.11	0.35	3.5	6.2
Equivalent Annualized Value	0.33	0.56	0.011	0.034	0.34	0.60
Less Stringent Scenario						
Present Value	3.4	5.8	0.11	0.36	3.5	6.2
Equivalent Annualized Value	0.33	0.56	0.010	0.035	0.34	0.60
More Stringent Scenario						
Present Value	3.4	5.8	0.41	0.63	3.8	6.4
Equivalent Annualized Value	0.33	0.56	0.039	0.061	0.37	0.62

[a] 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.

8.5.2 Climate Benefits

Table 8-20 presents the estimated climate benefits in PV and EAV terms for the three illustrative scenarios at a three percent discount rate. All estimates in the tables are presented as rounded values.

Table 8-20 Present Values and Equivalent Annualized Values of Estimated Climate Benefits for the Three Illustrative Scenarios for 2028 to 2042, Calculated using 3 Percent Discount Rate (billion 2019 dollars)[a,b]

Climate Benefits Calculated using 3% Discount Rate						
	111(d) for Existing Gas		111(b) for New Gas		Total Climate Benefits	
	Low	High	Low	High	Low	High
Illustrative Proposal Scenario						
Present Value	10	19	0.049	0.56	10	20
Equivalent Annualized Value	0.70	1.3	0.0034	0.039	0.70	1.4
Illustrative Less Stringent Scenario						
Present Value	10	19	0.044	0.56	10	20
Equivalent Annualized Value	0.70	1.3	0.0031	0.039	0.71	1.4
Illustrative More Stringent Scenario						
Present Value	10	19	0.50	0.94	11	20
Equivalent Annualized Value	0.70	1.3	0.035	0.066	0.74	1.4

[a] PV and EAV values discounted to 2024. Values have been rounded to two significant figures. Values may not appear to add correctly due to rounding.
[b] Climate benefits in this table are based on estimates of the SC-CO_2 at a 3 percent discount rate.

As seen by comparing Table 8-18 and Table 8-20, the estimated climate benefits significantly outweigh the estimated compliance costs under all three illustrative scenarios in this analysis, both for the Low estimates and the High estimates.

8.6 Limitations and Uncertainties

Section 3.7 outlines the uncertainties and limitations of the IPM-based analysis of the proposed 111(b) standards on new natural gas-fired EGUs and 111(d) standards on existing coal-fired EGUs, as described in Section 3.2. The analysis of the impacts associated with analysis of proposed 111(d) standards on existing natural gas-fired EGUs and some elements of the proposed 111(b) standards on new natural gas-fired EGUs[165] presented in Section 8 relies on these model runs to determine the baseline for the additional spreadsheet-based analysis. As such all the limitations and uncertainties outlined under Section 3.7 also apply to the estimates presented in Section 8.

[165] Specifically, the requirement for new gas-fired capacity operating at greater than 50 percent annual capacity factor in run year 2040 to increase hydrogen co-firing to 95 percent by volume or convert to CCS was not modeled.

While the spreadsheet-based analysis was informed by EPA's expert judgement, it was not based on any incremental IPM runs that would identify the least-cost compliance pathways for affected sources given the additional standards modeled. As such, the results from this analysis could differ from the compliance behavior that would be projected under incremental IPM modeling. Additionally, retail electricity price impacts are not estimated using the retail price model. Also, please see Section 5.2 for discussion regarding social cost estimation in the context of this proposed rulemaking.

EPA also is unable to estimate changes in pollutants other than CO_2 in the analysis presented in this section. As a result, we are unable quantify or monetize impacts associated with $PM_{2.5}$ or ozone-related concentration changes due to changes in $PM_{2.5}$, NO_X, and SO_2 emissions. Similarly, we are unable to analyze potential environmental justice impact that may be associated with changes in emissions of these pollutants.

8.7 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

APPENDIX A: AIR QUALITY MODELING

As noted in Section 4, EPA used photochemical modeling to create air quality surfaces[166] that were then used in air pollution health benefits calculations of the three illustrative scenarios of the proposed rules.[167] 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 and 2040. 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).

The ozone source apportionment modeling outputs are the same as those created for the Regulatory Impact Analysis for the proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard (U.S. EPA, 2022b). New PM source apportionment modeling outputs were created using the same inputs and modeling configuration as were used for the available ozone source apportionment modeling. The basic methodology for determining air quality changes is the same as that used in the RIAs from multiple previous rules (EPA, 2020; U.S. EPA, 2019, 2020b, 2021b, 2022c). EPA calculated EGU emissions estimates of NO_X and SO_2 for baseline and illustrative scenarios in all four 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).[168] 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.

[166] The term "air quality surfaces" refers to continuous gridded spatial fields using a 12 km grid resolution.

[167] Appendix A pertains to the analysis of the proposed standards for new natural gas-fired EGUs and for existing coal-fired EGUs. Please see Section 8 for impact analysis of the proposed standards for existing natural gas-fired EGUs and the third phase of the proposed standards for new natural gas-fired EGUs.

[168] 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

A.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.[169,170] The air quality modeling included photochemical model simulations for a 2016 base year and 2026 future year to provide hourly concentrations of ozone and $PM_{2.5}$ component species nationwide. In addition, source apportionment modeling was performed for 2026 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 electric generating units (EGUs) on a state-by-state basis. As described below, the modeling results for 2016 and 2026, in conjunction with EGU emissions data for the baseline and three illustrative scenarios in 2028, 2030, 2035 and 3040 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 (Ramboll Environ, 2021).[171] 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 A-1.

[169] Information on the emissions inventories used for the modeling described in U.S. EPA (2022e)

[170] The air quality modeling performed to support the analyses in this proposed RIA can be found in the *Air Quality Modeling Technical Support Document Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standards Proposed Rulemaking* (U.S. EPA, 2022b)

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

Figure A-1 Air Quality Modeling Domain

The contributions to ozone and $PM_{2.5}$ component species (e.g., sulfate, nitrate, ammonium, elemental carbon (EC), organic aerosol (OA), and crustal material[172]) from EGU emissions in individual states 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[173] 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 2026 modeled case to obtain the contributions from EGUs emissions in each state 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

[172] 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.

[173] Hourly contribution information is provided for each grid cell to provide spatial patterns of the contributions from each tag

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 A-1 provides state-level 2026 EGU emissions that were tracked for each source apportionment tag.

Table A-1 2026 Emissions Allocated to Each Modeled State-EGU Source Apportionment Tag

State Tag	Ozone Season NO_X Emissions (tons)	Annual NO_X emissions (tons)	Annual SO_2 emissions (tons)	Annual $PM_{2.5}$ emissions (tons)
AL	6,205	9,319	1,344	2,557
AR	5,594	9,258	22,306	1,075
AZ	1,341	3,416	2,420	814
CA	6,627	16,286	249	4,810
CO	5,881	12,725	7,311	1,556
CT	1,673	3,740	845	467
DC	37	39	0	53
DE	203	320	126	119
FL	11,590	22,451	8,784	6,555
GA	3,199	5,937	1,177	2,452
IA	8,008	17,946	9,042	1,182
ID	375	705	1	185
IL	8,244	16,777	31,322	3,018
IN	11,052	36,007	34,990	6,281
KS	3,166	4,351	854	709
KY	11,894	25,207	22,940	10,476
LA	10,895	16,949	11,273	3,119
MA	2,115	4,566	839	384
MD	1,484	3,008	273	783
ME	1,233	3,063	1,147	414
MI	11,689	22,378	31,387	3,216
MN	4,192	9,442	7,189	481
MO	10,075	34,935	105,916	3,617
MS	3,631	5,208	30	1,240
MT	3,908	8,760	3,527	1,426
NC	7,175	15,984	6,443	2,720
ND	8,053	19,276	26,188	1,265
NE	8,670	20,274	45,869	1,530
NH	224	483	159	93
NJ	1,969	4,032	915	729
NM	1,266	1,987	0	304
NV	1,577	3,017	0	901
NY	6,248	11,693	1,526	1,649
OH	9,200	27,031	46,780	4,543
OK	2,412	3,426	2	828
OR	1,122	2,145	29	455

State Tag	Ozone Season NO_X Emissions (tons)	Annual NO_X emissions (tons)	Annual SO_2 emissions (tons)	Annual $PM_{2.5}$ emissions (tons)
PA	12,386	23,965	9,685	3,785
RI	233	476	0	68
SC	3,251	7,134	6,292	2,082
SD	478	1,054	889	55
TL*	1,337	2,970	6,953	1,329
TN	790	2,100	1,231	845
TX	16,548	27,164	19,169	5,027
UT	3,571	10,915	11,040	693
VA	3,607	7,270	820	1,805
VT	2	4	0	4
WA	11,78	2,532	158	384
WI	2,097	4,304	821	1,084
WV	7,479	21,450	28,513	2,180
WY	5,026	11,036	8,725	629

* TL represents emissions occurring on tribal lands

Examples of the magnitude and spatial extent of ozone and $PM_{2.5}$ contributions are provided in Figure A-2 through Figure A-5 for EGUs in California, Texas, 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 volatile organic compound (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 in Iowa and California are similar in the 2026 modeling (Table A-1), the emissions from California lead to larger contributions to the formation of those pollutants due to the conducive conditions in that state. Texas and Ohio both had larger NO_X emissions than California or Iowa. While maximum ozone impacts shown for Texas and Ohio EGUs are similar order of magnitude to maximum ozone impacts from California EGUs, nitrate impacts are much smaller in Ohio and negligible in Texas due to less conducive atmospheric conditions for nitrate formation in those locations. California

EGU SO_2 emissions in the 2026 modeling are several orders of magnitude smaller than SO_2 emissions in Ohio and Texas (Table A-1) leading to much smaller sulfate contributions from California EGUs than from Ohio and Texas 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 is able capture important atmospheric processes which impact pollutant formation and transport form emissions sources.

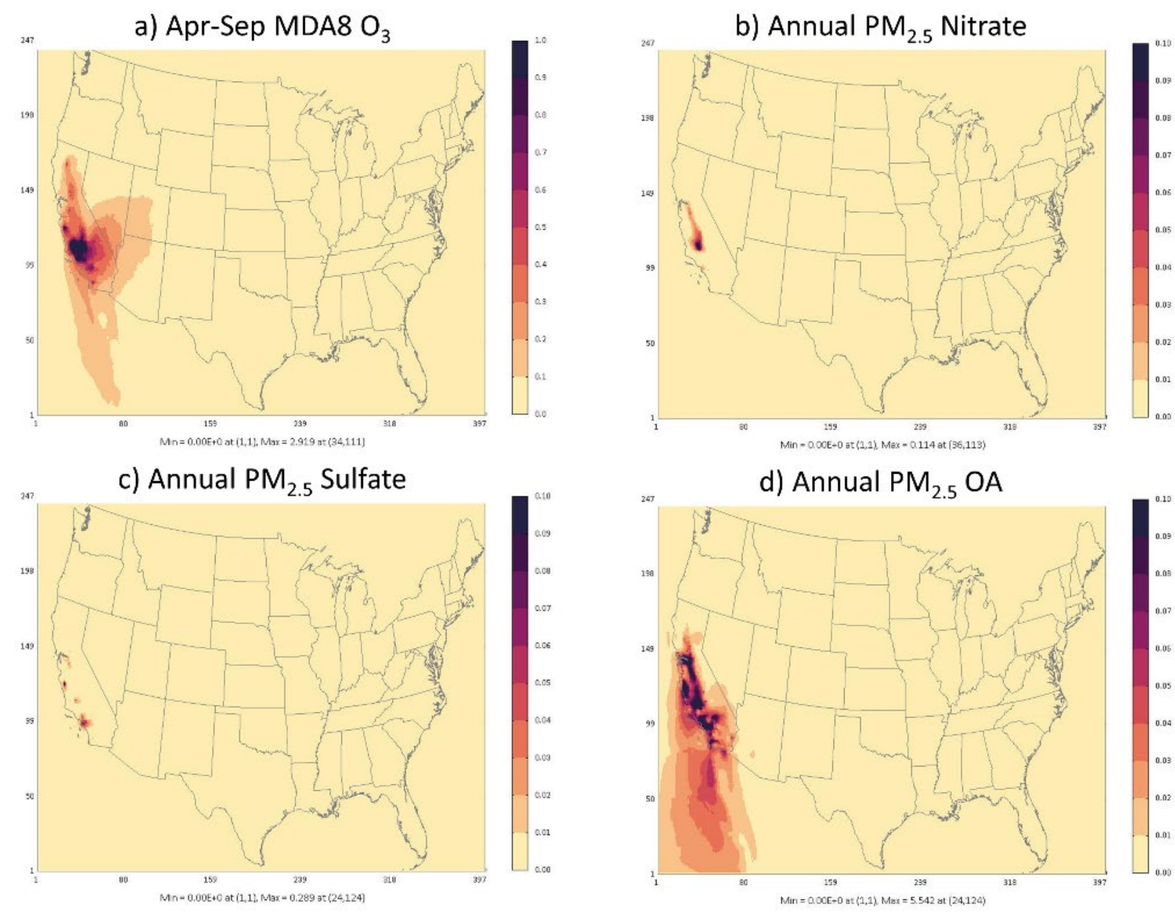

Figure A-2 Maps of California EGU Tag contributions to a) April-September Seasonal Average MDA8 Ozone (ppb); b) Annual Average $PM_{2.5}$ Nitrate ($\mu g/m^3$); c) Annual Average $PM_{2.5}$ sulfate ($\mu g/m^3$); d) Annual Average $PM_{2.5}$ Organic Aerosol ($\mu g/m^3$)

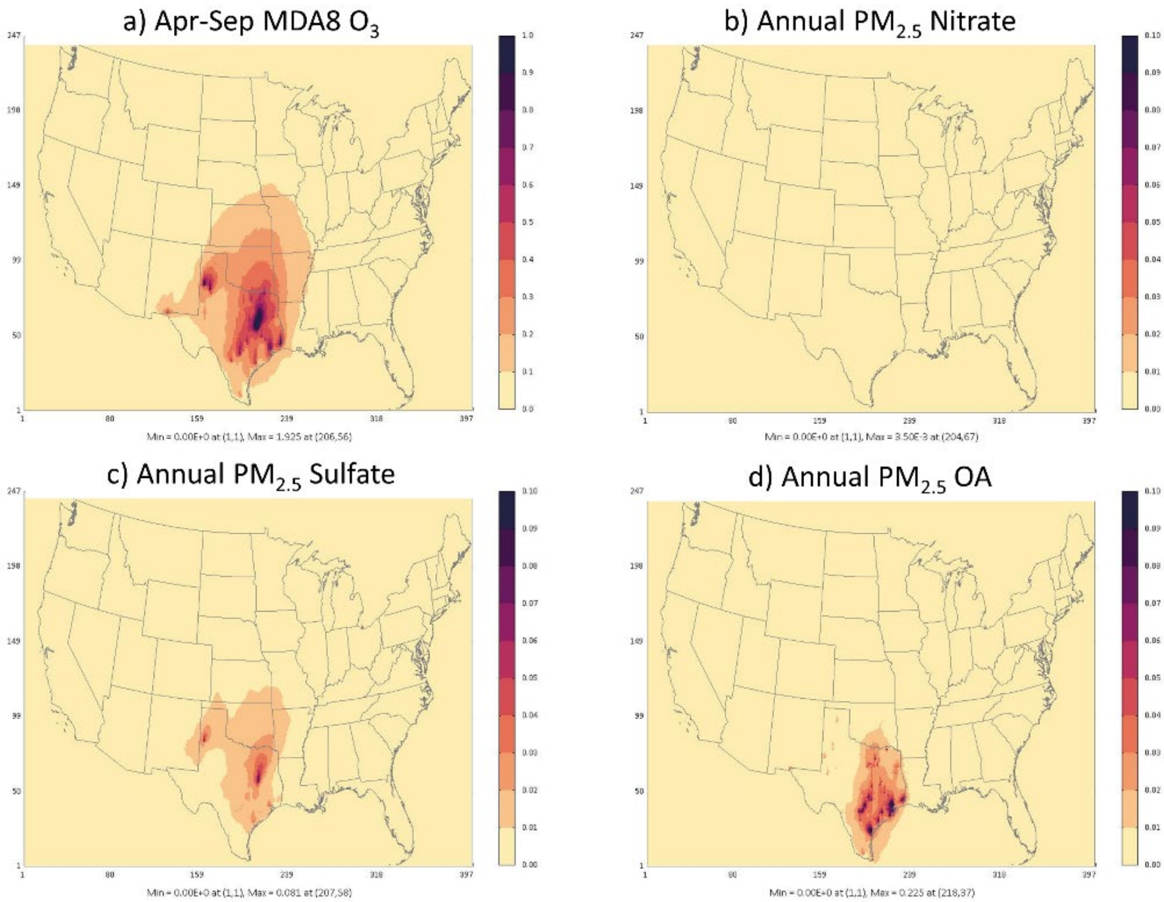

Figure A-3 Maps of Texas EGU Tag contributions to a) April-September Seasonal Average MDA8 Ozone (ppb); b) Annual Average $PM_{2.5}$ Nitrate ($\mu g/m^3$); c) Annual Average $PM_{2.5}$ sulfate ($\mu g/m^3$); d) Annual Average $PM_{2.5}$ Organic Aerosol ($\mu g/m^3$)

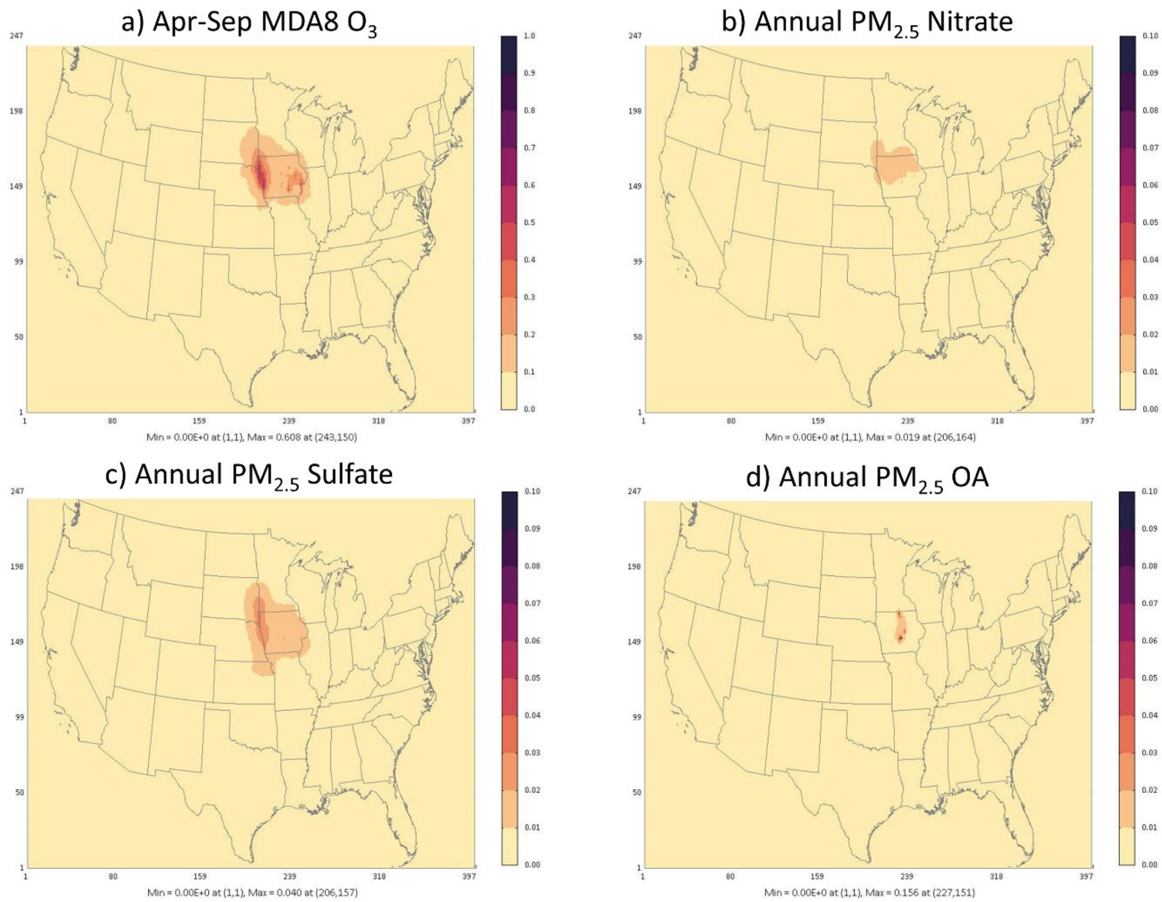

Figure A-4 Maps of Iowa EGU Tag contributions to a) April-September Seasonal Average MDA8 Ozone (ppb); b) Annual Average $PM_{2.5}$ Nitrate ($\mu g/m^3$); c) Annual Average $PM_{2.5}$ sulfate ($\mu g/m^3$); d) Annual Average $PM_{2.5}$ Organic Aerosol ($\mu g/m^3$)

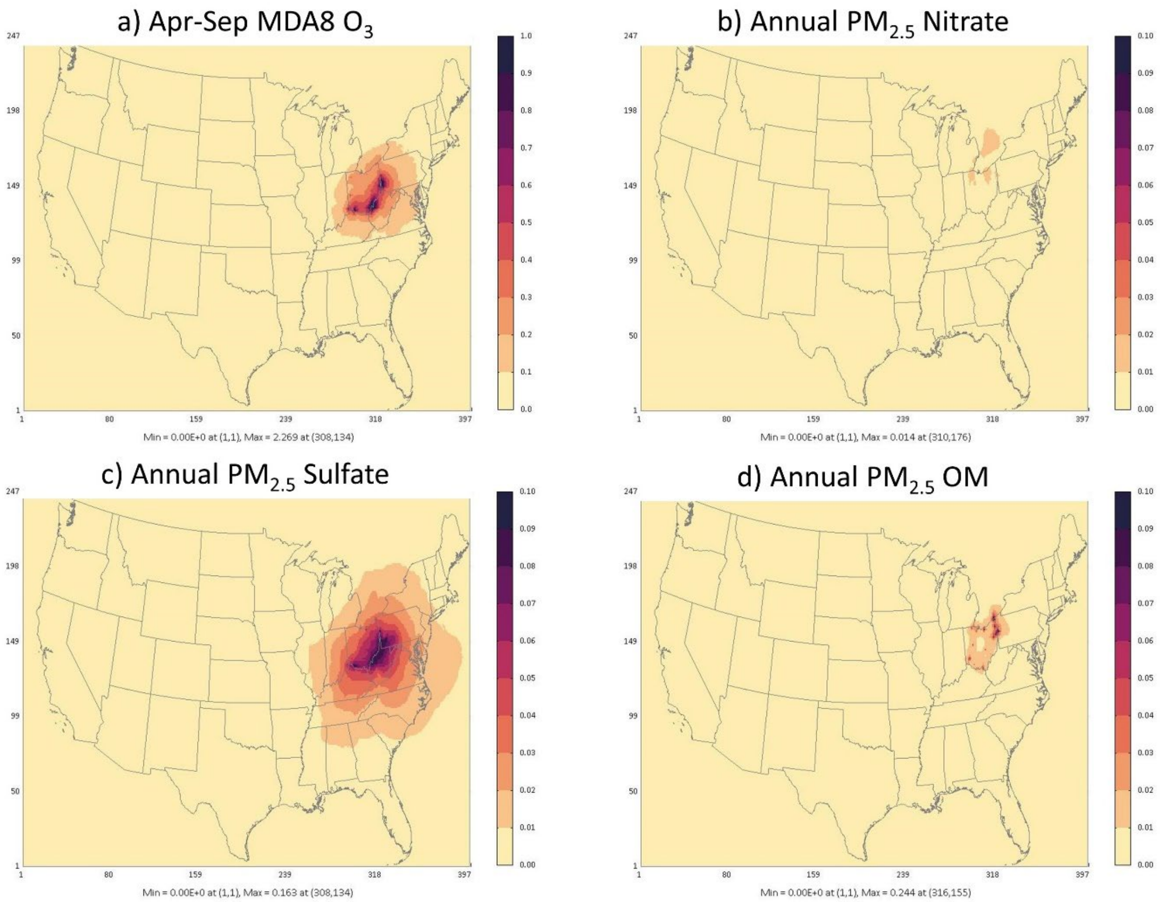

Figure A-5 Maps of Ohio EGU Tag contributions to a) April-September Seasonal Average MDA8 Ozone (ppb); b) Annual Average $PM_{2.5}$ Nitrate ($\mu g/m^3$); c) Annual Average $PM_{2.5}$ sulfate ($\mu g/m^3$); d) Annual Average $PM_{2.5}$ Organic Aerosol ($\mu g/m^3$)

A.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 2026 modeling. The foundational data include (1) ozone and speciated $PM_{2.5}$ concentrations in each model grid cell from the 2016 and 2026 modeling, (2) ozone and speciated $PM_{2.5}$ contributions in 2026 of EGUs emissions from each state in each model grid cell[174], (3) 2026 emissions from EGUs that were input to the contribution modeling (Table A-1), 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

[174] Contributions from EGUs were modeled using projected emissions for 2026. The resulting contributions were used to construct spatial fields in 2028, 2030, 2035 and 2040.

gridded source apportionment contributions based on emissions changes between 2026 projections and the baseline and the three illustrative scenarios to the 2026 contributions.

Spatial fields of ozone and $PM_{2.5}$ in 2026 were created based on "fusing" modeled data with measured concentrations at air quality monitoring locations. To create the spatial fields for each future emissions scenario, the fused 2026 model fields are used in combination with 2026 state-EGU source apportionment modeling and the EGU emissions for each scenario and snapshot year. Contributions from each state-EGU contribution "tag" were scaled based on the ratio of emissions in the year/scenario being evaluated to the emissions in the modeled 2026 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 2026 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 (SMAT-CE)[175] (U.S. EPA, 2022d) 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 2026 to calculate the ratio of AS-MO3 between 2016 and 2026 in each model grid cell.

[175] SMAT-CE available for download at https://www.epa.gov/scram/photochemical-modeling-tools.

1.3. To create a gridded 2026 eVNA surfaces, the spatial fields of 2016/2026 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 2026 using (Eq-1).

$$eVNA_{g,2026} = \left(eVNA_{g,2016}\right) \times \frac{Model_{g,2026}}{Model_{g,2016}} \qquad \text{Eq-1}$$

- $eVNA_{g,2026}$ is the eVNA concentration of AS-MO3 or $PM_{2.5}$ component species in grid-cell, g, in the 2026 future year
- $eVNA_{g,2016}$ is the eVNA concentration of AS-MO3 or $PM_{2.5}$ component species in grid-cell, g, in 2016
- $Model_{g,2026}$ is the CAMx modeled concentration of AS-MO3 or $PM_{2.5}$ component species in grid-cell, g, in the 2026 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 2026 modeled EGU ozone season emissions (Table A-1) to calculate the ratio of 2028 baseline emissions to 2026 modeled emissions for each EGU state contribution tag (i.e., an ozone scaling factor calculated for each state)[176]. These scaling factors are provided in Table A-2.

2.2. Calculate adjusted gridded AS-MO3 EGU contributions that reflect differences in state-EGU NO_X emissions between 2026 and the 2028 baseline by multiplying the ozone

[176] 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, scaling factors of 1.00 were applied to any tags that tracked less than 100 tpy emissions in the original source apportionment modeling. Any emissions changes in the low emissions state were assigned to a nearby state as denoted in Table A-2 through Table A-5.

season NO_X scaling factors by the corresponding gridded AS-MO3 ozone contributions[177] from each state-EGU tag.

2.3. Add together the adjusted AS-MO3 contributions for each EGU-state tag to produce spatial fields of adjusted EGU totals for the 2028 baseline.[178]

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 A-2.

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:

$$AS\text{-}MO3_{g,i,y} = eVNA_{g,2026} \times \left(\frac{C_{g,BC}}{C_{g,Tot}} + \frac{C_{g,int}}{C_{g,Tot}} + \frac{C_{g,bio}}{C_{g,Tot}} + \frac{C_{g,fires}}{C_{g,Tot}} + \frac{C_{g,USanthro}}{C_{g,Tot}} + \sum_{t=1}^{T} \frac{C_{EGUVOC,g,t}}{C_{g,Tot}} + \sum_{t=1}^{T} \frac{C_{EGUNOx,g,t}\, S_{NOx,t,i,y}}{C_{g,Tot}} \right) \qquad \text{Eq-2}$$

- $AS\text{-}MO3_{g,i,y}$ is the estimated fused model-obs AS-MO3 for grid-cell, "g", scenario, "i"[179], and year, "y"[180];
- $eVNA_{g,2026}$ is the 2026 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 2026 source apportionment modeling

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177 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.

178 The contributions from the unaltered O3V tags are added to the summed adjusted O3N EGU tags.

179 Scenario "i" can represent either the baseline or one of the three illustrative scenarios

180 Snapshot year "y" can represent 2028, 2030, 2035 or 2040

- $C_{g,BC}$ is the 2026 AS-MO3 modeled contribution from the modeled boundary inflow;
- $C_{g,int}$ is the 2026 AS-MO3 modeled contribution from international emissions within the modeling domain;
- $C_{g,bio}$ is the 2026 AS-MO3 modeled contribution from biogenic emissions;
- $C_{g,fires}$ is the 2026 AS-MO3 modeled contribution from fires;
- $C_{g,USanthro}$ is the total 2026 AS-MO3 modeled contribution from U.S. anthropogenic sources other than EGUs;
- $C_{EGUVOC,g,t}$ is the 2026 AS-MO3 modeled contribution from EGU emissions of VOCs from state, “t”;
- $C_{EGUNOx,g,t}$ is the 2026 AS-MO3 modeled contribution from EGU emissions of NO_X from state, “t”; and
- $S_{NOx,t,i,y}$ is the EGU NO_X scaling factor for state, “t”, scenario “i”, and year, “y”.

$PM_{2.5}$

4. Create fused spatial fields of 2026 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 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 2026 to calculate the ratio of $PM_{2.5}$ component species between 2016 and 2026 in each model grid cell.

    4.3. To create a gridded 2026 eVNA surfaces, the spatial fields of 2016/2026 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 2026 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 2026 modeled EGU NO_X, SO_2, and $PM_{2.5}$ emissions from Table A-1 to calculate the ratio of 2028 baseline emissions to 2026 modeled emissions for each EGU state contribution tag (i.e., annual nitrate, sulfate and directly emitted $PM_{2.5}$ scaling factors calculated for each state)[181]. These scaling factors are provided in Table A-3, Table A-4 and Table A-5.

   5.2. Calculate adjusted gridded annual $PM_{2.5}$ component species EGU contributions that reflect differences in state-EGU NO_X, SO_2, and primary $PM_{2.5}$ emissions between 2026 and the 2028 baseline by multiplying the annual nitrate, sulfate and directly emitted $PM_{2.5}$ scaling factors by the corresponding annual gridded $PM_{2.5}$ component species contributions from each state-EGU tag[182].

   5.3. Add together the adjusted $PM_{2.5}$ contributions of for each EGU state 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 A-3, Table A-4 and Table A-5.

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

[181] 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, scaling factors of 1.00 were applied to any tags that had less than 100 tpy emissions in the original source apportionment modeling. Any emissions changes in the low emissions state were assigned to a nearby state as denoted in Table A-2 through Table A-5.

[182] 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 2026 modeled emissions and the baseline and the three illustrative scenarios in each snapshot year.

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, 2022d).

Steps 5 and 6 result in Eq-3 for $PM_{2.5}$ component species: sulfate, nitrate, organic aerosol, elemental carbon and crustal material.

$$PM_{s,g,i,y} = eVNA_{s,g,2026} \times \left(\frac{C_{s,g,BC}}{C_{s,g,Tot}} + \frac{C_{s,g,int}}{C_{s,g,Tot}} + \frac{C_{s,g,bio}}{C_{s,g,Tot}} + \frac{C_{s,g,fires}}{C_{s,g,Tot}} + \frac{C_{s,g,USanthro}}{C_{s,g,Tot}} + \sum_{t=1}^{T} \frac{C_{EGUs,g,t}\, S_{s,t,i,y}}{C_{s,g,Tot}} \right) \qquad \text{Eq-3}$$

- $PM_{s,g,i,y}$ is the estimated fused model-obs PM component species "s" for grid-cell, "g", scenario, "i"[183], and year, "y"[184];
- $eVNA_{s,g,2026}$ is the 2026 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 2026 source apportionment modeling
- $C_{s,g,BC}$ is the 2026 PM component species "s" modeled contribution from the modeled boundary inflow;
- $C_{s,g,int}$ is the 2026 PM component species "s" modeled contribution from international emissions within the modeling domain;
- $C_{s,g,bio}$ is the 2026 PM component species "s" modeled contribution from biogenic emissions;

[183] Scenario "i" can represent either baseline or one of the illustrative scenarios.
[184] Snapshot year "y" can represent 2028, 2030, 2035, or 2040

- $C_{s,g,fires}$ is the 2026 PM component species "s" modeled contribution from fires;
- $C_{s,g,USanthro}$ is the total 2026 PM component species "s" modeled contribution from U.S. anthropogenic sources other than EGUs;
- $C_{EGUs,g,t}$ is the 2026 PM component species "s" modeled contribution from EGU emissions of NO_X, SO_2, or primary $PM_{2.5}$ from state, "t"; and
- $S_{s,t,i,y}$ is the EGU scaling factor for component species "s", state, "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

A.3 Scaling Factors Applied to Source Apportionment Tags

Table A-2 Ozone Scaling Factors for EGU Tags in the Baseline and Illustrative Scenarios

State	Baseline				Proposal				Less Stringent				More Stringent			
Tag	2028	2030	2035	2040	2028	2030	2035	2040	2028	2030	2035	2040	2028	2030	2035	2040
AL	0.85	0.89	0.58	0.27	0.85	0.82	0.57	0.28	0.85	0.82	0.57	0.28	0.86	0.80	0.56	0.26
AR	0.38	0.27	0.20	0.11	0.33	0.34	0.22	0.12	0.33	0.39	0.21	0.11	0.38	0.43	0.23	0.15
AZ	1.28	2.05	2.80	2.64	1.27	2.21	2.92	2.90	1.27	2.21	2.89	2.88	1.27	2.21	2.80	2.88
CA	0.69	0.37	0.27	0.28	0.70	0.52	0.29	0.27	0.70	0.52	0.29	0.28	0.81	0.41	0.32	0.26
CO	0.71	0.16	0.16	0.09	0.68	0.19	0.17	0.09	0.65	0.18	0.17	0.09	0.72	0.22	0.18	0.09
CT	0.71	0.70	0.66	0.00	0.71	0.71	0.66	0.00	0.71	0.72	0.66	0.00	0.72	0.72	0.66	0.00
DC	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
DE	1.68	1.68	0.96	0.95	1.68	2.37	0.99	0.95	1.68	2.37	0.99	0.95	1.68	2.38	0.99	0.96
FL	1.09	1.02	0.91	0.83	1.09	1.05	0.86	0.81	1.09	1.04	0.87	0.82	1.06	1.05	0.87	0.81
GA	1.23	1.32	0.70	0.60	1.22	1.20	0.80	0.63	1.22	1.18	0.80	0.64	1.24	1.21	0.80	0.64
IA	1.28	0.96	0.05	0.02	1.27	0.45	0.04	0.03	1.28	0.58	0.04	0.03	1.29	0.42	0.04	0.03
ID	1.06	1.16	0.37	0.48	1.28	1.42	0.45	0.53	1.28	1.42	0.45	0.53	1.18	1.29	0.60	0.66
IL	0.42	0.40	0.27	0.08	0.42	0.53	0.34	0.29	0.42	0.50	0.34	0.29	0.42	0.52	0.34	0.29
IN	0.75	0.55	0.22	0.19	0.90	0.41	0.22	0.19	0.90	0.41	0.22	0.19	0.91	0.42	0.22	0.19
KS	1.02	0.16	0.06	0.05	1.01	0.20	0.06	0.05	1.01	0.19	0.06	0.05	1.01	0.20	0.05	0.05
KY	0.36	0.40	0.20	0.19	0.38	0.41	0.30	0.29	0.38	0.41	0.30	0.30	0.40	0.42	0.27	0.26
LA	0.47	0.46	0.32	0.21	0.47	0.48	0.31	0.22	0.47	0.48	0.31	0.22	0.47	0.49	0.31	0.21
MA	1.20	1.21	1.17	1.23	1.20	1.21	1.16	1.24	1.20	1.21	1.16	1.24	1.22	1.21	1.16	1.25
MD	0.74	0.74	0.70	0.64	0.75	0.87	0.70	0.64	0.74	0.95	0.70	0.64	0.75	1.55	0.70	0.64
ME	1.63	1.14	1.07	1.16	1.63	1.14	1.07	1.16	1.63	1.14	1.07	1.16	1.63	1.14	1.07	1.16
MI	0.73	0.74	0.57	0.35	0.72	0.79	0.61	0.35	0.72	0.76	0.61	0.35	0.73	0.81	0.60	0.36
MN	0.67	0.31	0.14	0.12	0.60	0.37	0.13	0.12	0.61	0.37	0.13	0.12	0.65	0.37	0.13	0.12
MO	0.53	0.25	0.04	0.05	0.51	0.13	0.03	0.02	0.51	0.18	0.05	0.04	0.53	0.13	0.04	0.02
MS	0.73	0.73	0.62	0.29	0.73	0.74	0.72	0.29	0.73	0.74	0.73	0.31	0.73	0.76	0.72	0.31
MT	1.01	0.97	0.93	0.43	1.01	0.27	0.04	0.04	1.01	0.27	0.04	0.04	1.01	0.16	0.04	0.04
NC	0.56	0.36	0.33	0.31	0.53	0.33	0.33	0.32	0.53	0.33	0.33	0.32	0.57	0.36	0.33	0.31
ND	1.46	1.07	0.50	0.50	1.46	0.18	0.07	0.07	1.46	0.19	0.07	0.07	1.46	0.13	0.07	0.07
NE	1.15	0.91	0.13	0.11	1.14	0.11	0.01	0.01	1.14	0.12	0.01	0.01	1.14	0.09	0.01	0.01
NH	1.25	1.30	1.04	1.12	1.25	1.33	1.10	1.14	1.25	1.33	1.10	1.14	1.32	1.32	1.11	1.13
NJ	1.06	1.07	0.96	0.85	1.06	1.20	0.95	0.87	1.07	1.19	0.95	0.86	1.08	1.26	0.97	0.93

State Tag	Baseline				Proposal				Less Stringent				More Stringent			
	2028	2030	2035	2040	2028	2030	2035	2040	2028	2030	2035	2040	2028	2030	2035	2040
NM	0.58	0.58	0.46	0.33	0.59	0.74	0.46	0.39	0.59	0.74	0.46	0.39	0.63	0.56	0.46	0.39
NV	0.74	1.12	0.98	0.58	0.75	1.17	0.97	0.46	0.75	1.18	0.97	0.46	0.78	0.79	0.77	0.46
NY	0.89	0.85	0.64	0.52	0.90	0.85	0.64	0.52	0.90	0.85	0.64	0.52	0.90	0.85	0.64	0.52
OH	0.78	0.59	0.32	0.28	0.77	0.45	0.28	0.26	0.77	0.44	0.28	0.26	0.78	0.44	0.27	0.26
OK	0.74	0.67	0.12	0.02	0.73	0.83	0.12	0.02	0.73	0.83	0.16	0.06	0.73	0.88	0.14	0.02
OR	0.33	0.10	0.00	0.00	0.33	0.10	0.00	0.00	0.33	0.10	0.00	0.00	0.35	0.10	0.00	0.00
PA	0.65	0.74	0.57	0.34	0.65	0.88	0.53	0.34	0.65	0.84	0.53	0.34	0.66	0.98	0.54	0.34
RI	1.26	1.26	1.13	1.35	1.26	1.28	1.12	1.35	1.26	1.26	1.12	1.35	1.26	1.26	1.12	1.36
SC	0.98	0.61	0.43	0.34	0.60	0.55	0.41	0.30	0.60	0.55	0.41	0.30	0.84	0.53	0.43	0.31
SD	1.33	1.06	0.08	0.02	1.35	0.48	0.08	0.03	1.35	0.38	0.08	0.03	1.34	0.38	0.08	0.03
TL	1.08	1.03	0.00	0.01	1.08	0.17	0.00	0.01	1.08	0.17	0.00	0.01	1.08	0.13	0.00	0.01
TN	1.99	0.92	0.57	0.55	1.96	0.95	0.58	0.50	1.96	0.99	0.57	0.50	2.11	0.93	0.50	0.47
TX	0.73	0.64	0.44	0.45	0.72	0.66	0.42	0.40	0.72	0.65	0.42	0.40	0.73	0.67	0.42	0.40
UT	1.02	1.10	0.97	0.93	0.54	1.11	0.94	0.92	0.54	1.11	0.94	0.92	0.55	1.10	0.95	0.93
VA	1.22	1.00	0.89	0.67	1.02	1.21	0.81	0.65	1.02	1.21	0.81	0.65	1.23	1.20	0.80	0.70
VT	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
WA	0.71	0.79	0.49	0.49	0.71	0.94	0.49	0.49	0.71	0.94	0.49	0.49	0.71	0.75	0.49	0.49
WI	1.29	0.96	0.51	0.44	1.29	0.89	0.53	0.45	1.29	1.00	0.53	0.44	1.30	0.94	0.53	0.45
WV	1.03	0.82	0.28	0.01	1.01	0.44	0.29	0.01	1.05	0.50	0.32	0.01	1.06	0.46	0.31	0.00
WY	0.70	0.61	0.62	0.41	0.70	0.63	0.62	0.42	0.70	0.63	0.62	0.42	0.70	0.62	0.62	0.42

*TL = tribal lands

**Scaling factors of 1.00 were applied to tags that had less than 100 tpy emissions assigned in the original source apportionment modeling. Any emissions changes in that state were assigned to a nearby state. For NO_x, the following emissions change assignments were applied: DC → MD, VT → NY

Table A-3 Nitrate Scaling Factors for EGU Tags in the Baseline and Illustrative Scenarios

State Tag	Baseline				Proposal				Less Stringent				More Stringent			
	2028	2030	2035	2040	2028	2030	2035	2040	2028	2030	2035	2040	2028	2030	2035	2040
AL	1.08	1.13	0.63	0.31	1.07	1.06	0.62	0.33	1.07	1.06	0.62	0.33	1.08	1.04	0.60	0.31
AR	0.43	0.34	0.17	0.09	0.40	0.36	0.19	0.10	0.40	0.43	0.18	0.09	0.46	0.50	0.21	0.13
AZ	1.36	1.66	1.80	1.64	1.35	1.78	2.21	1.76	1.35	1.78	2.20	1.75	1.40	1.77	2.17	1.75
CA	0.59	0.42	0.30	0.30	0.59	0.48	0.32	0.31	0.59	0.48	0.32	0.32	0.71	0.44	0.35	0.30
CO	0.57	0.16	0.18	0.14	0.56	0.18	0.20	0.14	0.54	0.17	0.20	0.14	0.56	0.21	0.19	0.13
CT	0.68	0.65	0.58	0.00	0.68	0.66	0.58	0.00	0.68	0.66	0.58	0.00	0.68	0.67	0.58	0.00
DC	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
DE	1.66	1.66	0.94	0.88	1.65	2.27	1.06	0.88	1.66	2.23	1.02	0.88	1.66	2.38	1.11	0.90
FL	1.15	1.04	0.98	0.89	1.15	1.07	0.97	0.88	1.15	1.06	0.97	0.88	1.12	1.07	0.97	0.88
GA	1.30	1.28	0.72	0.57	1.29	1.24	0.78	0.60	1.29	1.23	0.78	0.60	1.31	1.21	0.78	0.60
IA	1.28	0.98	0.04	0.02	1.28	0.41	0.03	0.02	1.28	0.50	0.03	0.02	1.29	0.41	0.03	0.02
ID	0.98	1.07	0.66	0.87	1.24	1.36	0.88	1.03	1.24	1.36	0.88	1.03	1.12	1.22	0.93	1.15
IL	0.41	0.40	0.21	0.07	0.41	0.48	0.33	0.29	0.41	0.47	0.33	0.29	0.41	0.49	0.33	0.29
IN	0.77	0.57	0.15	0.13	0.81	0.37	0.15	0.13	0.82	0.36	0.15	0.13	0.82	0.37	0.15	0.13
KS	1.73	0.20	0.09	0.05	1.73	0.25	0.09	0.04	1.73	0.25	0.09	0.04	1.72	0.24	0.09	0.04
KY	0.47	0.41	0.25	0.22	0.48	0.47	0.35	0.32	0.48	0.47	0.35	0.32	0.51	0.45	0.32	0.29
LA	0.62	0.60	0.35	0.23	0.61	0.62	0.36	0.23	0.61	0.60	0.36	0.23	0.63	0.67	0.36	0.23
MA	1.22	1.22	1.18	1.18	1.22	1.23	1.18	1.19	1.22	1.23	1.18	1.20	1.24	1.23	1.18	1.19
MD	0.84	0.81	0.72	0.65	0.84	0.90	0.72	0.65	0.84	0.95	0.73	0.65	0.84	1.23	0.72	0.66
ME	1.49	1.08	0.93	0.81	1.49	1.08	0.93	0.88	1.49	1.08	0.93	0.88	1.49	1.08	0.93	0.88
MI	0.70	0.73	0.47	0.27	0.69	0.79	0.51	0.28	0.69	0.77	0.51	0.28	0.72	0.82	0.50	0.29

State Tag	Baseline				Proposal				Less Stringent				More Stringent			
	2028	2030	2035	2040	2028	2030	2035	2040	2028	2030	2035	2040	2028	2030	2035	2040
MN	0.62	0.27	0.13	0.09	0.57	0.30	0.11	0.09	0.57	0.30	0.11	0.09	0.59	0.30	0.11	0.09
MO	0.83	0.56	0.05	0.02	0.82	0.23	0.02	0.01	0.82	0.27	0.02	0.01	0.83	0.19	0.02	0.01
MS	0.88	0.99	0.66	0.36	0.85	1.03	0.72	0.31	0.85	1.03	0.74	0.34	0.87	1.04	0.72	0.34
MT	1.05	1.01	1.06	0.76	1.05	0.35	0.13	0.05	1.05	0.35	0.14	0.05	1.05	0.30	0.13	0.05
NC	0.75	0.32	0.30	0.29	0.72	0.29	0.31	0.29	0.72	0.30	0.31	0.29	0.75	0.34	0.30	0.27
ND	1.48	1.01	0.52	0.48	1.47	0.34	0.06	0.06	1.47	0.35	0.06	0.06	1.47	0.23	0.06	0.06
NE	1.11	0.88	0.14	0.10	1.11	0.13	0.02	0.01	1.11	0.14	0.02	0.01	1.11	0.11	0.02	0.01
NH	1.11	1.13	1.00	0.98	1.11	1.14	1.02	0.99	1.11	1.14	1.02	0.99	1.16	1.15	1.03	0.99
NJ	1.06	1.08	0.87	0.81	1.06	1.19	0.89	0.83	1.07	1.18	0.89	0.82	1.08	1.26	0.90	0.86
NM	0.56	0.57	0.48	0.28	0.57	0.69	0.52	0.40	0.57	0.69	0.52	0.40	0.66	0.58	0.52	0.40
NV	0.58	0.88	0.76	0.56	0.57	0.92	0.75	0.50	0.57	0.93	0.75	0.50	0.74	0.71	0.64	0.50
NY	0.94	0.92	0.70	0.55	0.94	0.92	0.71	0.55	0.94	0.92	0.71	0.56	0.95	0.92	0.71	0.56
OH	0.83	0.57	0.30	0.21	0.82	0.44	0.20	0.19	0.82	0.43	0.20	0.19	0.82	0.43	0.20	0.19
OK	0.85	0.80	0.18	0.08	0.83	1.07	0.13	0.02	0.83	1.07	0.19	0.08	0.86	1.13	0.15	0.02
OR	0.54	0.24	0.12	0.00	0.52	0.27	0.12	0.00	0.52	0.27	0.12	0.00	0.54	0.26	0.12	0.00
PA	0.65	0.75	0.54	0.38	0.64	0.84	0.51	0.36	0.65	0.82	0.51	0.36	0.66	0.95	0.52	0.36
RI	1.19	1.19	1.07	1.09	1.19	1.20	1.06	1.09	1.19	1.20	1.06	1.09	1.22	1.23	1.06	1.10
SC	1.01	0.63	0.49	0.43	0.75	0.62	0.38	0.29	0.75	0.62	0.38	0.30	0.89	0.59	0.39	0.31
SD	1.28	1.01	0.04	0.01	1.29	0.45	0.04	0.02	1.29	0.45	0.04	0.02	1.29	0.45	0.04	0.02
TL	0.93	0.93	0.00	0.00	0.93	0.29	0.00	0.00	0.93	0.28	0.00	0.00	0.93	0.26	0.00	0.00
TN	1.58	0.69	0.48	0.34	1.58	0.79	0.45	0.32	1.58	0.85	0.45	0.33	1.59	0.65	0.42	0.30
TX	0.97	0.85	0.54	0.49	0.95	0.82	0.47	0.42	0.95	0.82	0.47	0.42	0.96	0.85	0.48	0.43
UT	0.56	0.60	0.56	0.51	0.37	0.55	0.49	0.49	0.37	0.55	0.49	0.49	0.38	0.55	0.50	0.49
VA	1.29	1.08	0.89	0.73	1.04	1.18	0.84	0.69	1.06	1.18	0.85	0.69	1.31	1.23	0.83	0.72
VT	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
WA	0.72	0.97	0.94	0.92	0.72	0.95	0.91	0.94	0.72	0.95	0.91	0.94	0.79	0.87	0.91	0.95
WI	1.46	1.02	0.45	0.37	1.46	0.79	0.47	0.37	1.46	0.88	0.47	0.37	1.47	0.85	0.47	0.38
WV	1.08	0.70	0.30	0.02	1.07	0.50	0.23	0.00	1.09	0.53	0.25	0.01	1.09	0.51	0.24	0.00
WY	0.68	0.59	0.61	0.42	0.68	0.63	0.63	0.43	0.68	0.62	0.63	0.43	0.68	0.63	0.63	0.43

*TL = tribal lands

**Scaling factors of 1.00 were applied to tags that had less than 100 tpy emissions assigned in the original source apportionment modeling. Any emissions changes in that state were assigned to a nearby state. For NO_x, the following emissions change assignments were applied: DC → MD, VT → NY

Table A-4 Sulfate Scaling Factors for EGU Tags in the Baseline and Illustrative Scenarios

State Tag	Baseline				Proposal				Less Stringent				More Stringent			
	2028	2030	2035	2040	2028	2030	2035	2040	2028	2030	2035	2040	2028	2030	2035	2040
AL	1.88	1.79	0.61	0.61	1.98	1.42	0.26	0.26	1.86	1.10	0.47	0.41	2.17	1.33	0.15	0.15
AR	0.06	0.01	0.00	0.00	0.06	0.00	0.00	0.00	0.06	0.03	0.00	0.00	0.07	0.02	0.02	0.02
AZ	1.02	1.86	3.55	0.98	0.91	3.86	3.54	0.97	0.91	3.86	3.54	0.97	0.91	3.86	3.54	0.97
CA	2.42	0.43	0.40	0.40	2.42	0.30	0.25	0.00	2.42	0.30	0.25	0.17	2.42	0.26	0.25	0.00
CO	0.16	0.04	0.00	0.00	0.17	0.04	0.00	0.00	0.17	0.04	0.00	0.00	0.16	0.04	0.00	0.00
CT	0.55	0.55	0.55	0.00	0.55	0.55	0.55	0.00	0.55	0.55	0.55	0.00	0.55	0.55	0.55	0.00
DC	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
DE	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73
FL	1.50	0.99	0.81	0.81	1.49	0.94	0.42	0.42	1.50	0.96	0.55	0.55	1.44	0.92	0.42	0.42
GA	3.61	2.75	0.00	0.00	3.67	1.36	0.00	0.00	3.67	1.36	0.00	0.00	3.60	1.08	0.00	0.00
IA	1.23	0.95	0.04	0.00	1.23	0.27	0.00	0.00	1.23	0.41	0.00	0.00	1.23	0.26	0.00	0.00
ID	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

State	Baseline				Proposal				Less Stringent				More Stringent			
Tag	2028	2030	2035	2040	2028	2030	2035	2040	2028	2030	2035	2040	2028	2030	2035	2040
IL	0.29	0.22	0.09	0.00	0.29	0.22	0.22	0.18	0.29	0.22	0.22	0.18	0.29	0.22	0.22	0.18
IN	1.18	0.64	0.16	0.16	1.15	0.64	0.16	0.16	1.15	0.63	0.16	0.16	1.17	0.64	0.16	0.16
KS	3.03	0.00	0.00	0.00	3.02	0.08	0.00	0.00	3.02	0.06	0.00	0.00	3.02	0.00	0.00	0.00
KY	0.31	0.31	0.17	0.14	0.33	0.33	0.25	0.21	0.33	0.33	0.25	0.21	0.35	0.31	0.22	0.19
LA	0.18	0.03	0.03	0.03	0.11	0.08	0.03	0.03	0.18	0.08	0.03	0.03	0.11	0.08	0.03	0.03
MA	0.98	0.98	0.98	0.97	0.98	0.98	0.98	0.97	0.98	0.98	0.98	0.97	0.98	0.98	0.98	0.97
MD	2.62	1.99	0.99	0.99	2.62	1.89	0.99	0.99	2.62	2.61	0.99	0.99	2.62	1.89	0.99	0.99
ME	1.11	0.88	0.81	0.77	1.11	0.88	0.81	0.78	1.11	0.88	0.81	0.78	1.11	0.88	0.81	0.78
MI	0.24	0.41	0.40	0.01	0.23	0.41	0.40	0.01	0.23	0.41	0.40	0.01	0.24	0.41	0.40	0.01
MN	0.61	0.47	0.13	0.07	0.59	0.20	0.08	0.07	0.59	0.20	0.08	0.07	0.59	0.20	0.08	0.07
MO	0.43	0.31	0.03	0.04	0.43	0.11	0.00	0.00	0.43	0.15	0.01	0.01	0.43	0.09	0.00	0.00
MS	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
MT	1.36	1.15	1.10	0.88	1.36	0.42	0.19	0.11	1.36	0.43	0.19	0.15	1.36	0.42	0.19	0.11
NC	0.65	0.10	0.05	0.05	0.57	0.00	0.00	0.00	0.58	0.00	0.00	0.00	0.65	0.05	0.00	0.00
ND	1.10	0.95	0.71	0.68	1.09	0.65	0.41	0.41	1.09	0.65	0.41	0.41	1.09	0.49	0.41	0.41
NE	1.05	0.97	0.17	0.10	1.05	0.08	0.00	0.00	1.05	0.10	0.00	0.00	1.05	0.08	0.00	0.00
NH	0.52	0.52	0.52	0.48	0.52	0.52	0.52	0.48	0.52	0.52	0.52	0.48	0.52	0.52	0.52	0.48
NJ	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
NM	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
NV	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
NY	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98
OH	0.70	0.45	0.07	0.03	0.71	0.28	0.03	0.03	0.72	0.28	0.03	0.03	0.74	0.28	0.03	0.03
OK	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
OR	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
PA	0.78	0.58	0.30	0.24	0.74	0.60	0.15	0.06	0.77	0.60	0.14	0.06	0.78	0.62	0.17	0.06
RI	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
SC	1.44	0.55	0.24	0.19	0.82	0.47	0.00	0.00	0.82	0.47	0.00	0.00	1.20	0.47	0.00	0.00
SD	1.33	1.00	0.00	0.00	1.33	0.34	0.00	0.00	1.33	0.34	0.00	0.00	1.33	0.34	0.00	0.00
TL	0.98	0.98	0.00	0.00	0.98	0.28	0.00	0.00	0.98	0.27	0.00	0.00	0.98	0.27	0.00	0.00
TN	2.33	0.19	0.00	0.00	2.30	0.31	0.00	0.00	2.31	0.35	0.00	0.00	2.46	0.00	0.00	0.00
TX	1.48	0.66	0.72	0.72	1.37	0.44	0.33	0.33	1.39	0.43	0.34	0.34	1.41	0.43	0.34	0.34
UT	0.89	1.03	1.03	0.76	0.63	0.52	0.44	0.44	0.63	0.52	0.44	0.44	0.63	0.52	0.44	0.44
VA	1.13	1.13	0.93	0.91	1.13	0.91	0.80	0.80	1.13	0.91	0.80	0.80	1.13	0.91	0.80	0.80
VT	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
WA	0.34	0.21	0.21	0.16	0.34	0.21	0.21	0.16	0.34	0.21	0.21	0.16	0.34	0.21	0.21	0.16
WI	2.83	1.00	0.00	0.00	2.83	0.46	0.00	0.00	2.83	0.85	0.00	0.00	2.84	0.46	0.00	0.00
WV	1.15	0.58	0.17	0.01	1.14	0.37	0.12	0.00	1.16	0.41	0.13	0.00	1.16	0.38	0.12	0.00
WY	1.30	0.99	1.07	0.66	1.30	1.12	1.13	0.67	1.30	1.10	1.13	0.67	1.30	1.12	1.13	0.67

*TL = tribal lands

**Scaling factors of 1.00 were applied to tags that had less than 100 tpy emissions assigned in the original source apportionment modeling. Any emissions changes in that state were assigned to a nearby state. For SO_2, the following emissions change assignments were applied: DC → MD, ID → MT, MS → AL, NV → UT, NM → AZ, OK → TX, OR → WA, RI → CT, VT → NY

Table A-5 Primary $PM_{2.5}$ Scaling Factors for EGU Tags in the Baseline and Illustrative Scenarios

State	Baseline				Proposal				Less Stringent				More Stringent			
Tag	2028	2030	2035	2040	2028	2030	2035	2040	2028	2030	2035	2040	2028	2030	2035	2040
AL	1.06	1.08	0.80	0.58	1.06	1.00	0.80	0.60	1.06	1.00	0.80	0.60	1.06	0.99	0.79	0.59
AR	0.85	0.73	0.39	0.28	0.83	0.75	0.47	0.29	0.83	0.84	0.46	0.28	0.89	0.85	0.51	0.35
AZ	1.14	1.59	1.45	1.36	1.12	1.64	1.50	1.42	1.12	1.64	1.50	1.42	1.12	1.64	1.49	1.42

State Tag	Baseline 2028	Baseline 2030	Baseline 2035	Baseline 2040	Proposal 2028	Proposal 2030	Proposal 2035	Proposal 2040	Less Stringent 2028	Less Stringent 2030	Less Stringent 2035	Less Stringent 2040	More Stringent 2028	More Stringent 2030	More Stringent 2035	More Stringent 2040
CA	0.68	0.54	0.40	0.40	0.66	0.50	0.47	0.47	0.66	0.50	0.46	0.47	0.67	0.63	0.49	0.44
CO	0.63	0.34	0.35	0.26	0.62	0.36	0.37	0.27	0.60	0.35	0.37	0.26	0.63	0.41	0.35	0.27
CT	0.59	0.53	0.39	0.01	0.59	0.56	0.39	0.01	0.59	0.56	0.39	0.01	0.61	0.59	0.39	0.01
DC	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
DE	1.35	1.36	0.96	0.89	1.34	1.65	1.09	0.89	1.35	1.63	1.08	0.89	1.35	1.70	1.11	0.93
FL	0.98	0.93	0.89	0.81	0.98	0.93	0.88	0.81	0.98	0.93	0.89	0.81	0.97	0.93	0.88	0.81
GA	0.86	0.91	0.76	0.64	0.86	0.94	0.79	0.66	0.86	0.93	0.79	0.66	0.86	0.94	0.79	0.66
IA	1.45	1.20	0.18	0.08	1.45	0.67	0.15	0.09	1.45	0.82	0.15	0.09	1.45	0.69	0.15	0.09
ID	0.99	1.15	0.78	1.23	1.40	1.57	1.08	1.54	1.40	1.57	1.07	1.53	1.20	1.38	1.19	1.73
IL	0.41	0.42	0.25	0.14	0.41	0.47	0.29	0.23	0.41	0.46	0.29	0.23	0.42	0.49	0.29	0.23
IN	0.77	0.61	0.32	0.27	0.78	0.46	0.32	0.28	0.78	0.45	0.32	0.28	0.78	0.46	0.32	0.28
KS	1.06	0.12	0.05	0.03	1.05	0.14	0.06	0.03	1.05	0.14	0.06	0.02	1.05	0.14	0.06	0.03
KY	0.14	0.13	0.09	0.08	0.14	0.17	0.14	0.13	0.14	0.17	0.14	0.13	0.15	0.15	0.13	0.11
LA	0.87	0.87	0.68	0.55	0.86	0.91	0.69	0.56	0.87	0.90	0.69	0.56	0.86	0.88	0.67	0.55
MA	0.99	0.99	0.85	0.89	0.99	1.00	0.84	0.90	0.99	1.00	0.84	0.90	1.01	1.02	0.84	0.90
MD	0.67	0.65	0.51	0.39	0.68	0.73	0.56	0.39	0.68	0.78	0.59	0.39	0.68	0.86	0.54	0.39
ME	1.08	1.03	0.98	0.79	1.08	1.03	0.99	0.95	1.08	1.03	0.99	0.95	1.09	1.03	0.99	0.95
MI	0.58	0.65	0.49	0.37	0.57	0.68	0.52	0.37	0.57	0.67	0.52	0.37	0.58	0.68	0.51	0.38
MN	1.02	0.44	0.26	0.21	0.94	0.48	0.25	0.21	0.94	0.48	0.25	0.21	0.98	0.49	0.25	0.22
MO	0.46	0.29	0.07	0.05	0.44	0.20	0.06	0.03	0.44	0.24	0.06	0.04	0.46	0.20	0.06	0.03
MS	1.11	1.14	0.84	0.63	1.10	1.18	0.89	0.61	1.10	1.17	0.91	0.63	1.13	1.19	0.90	0.67
MT	0.97	0.96	0.97	0.72	0.97	0.35	0.18	0.11	0.97	0.35	0.18	0.11	0.97	0.33	0.17	0.11
NC	0.94	0.53	0.53	0.52	0.93	0.54	0.57	0.53	0.93	0.54	0.57	0.53	0.95	0.59	0.56	0.51
ND	2.03	1.51	0.62	0.52	2.02	0.54	0.14	0.13	2.02	0.61	0.14	0.13	2.02	0.42	0.14	0.13
NE	0.39	0.26	0.05	0.04	0.39	0.06	0.02	0.01	0.39	0.06	0.02	0.02	0.39	0.05	0.02	0.01
NH	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
NJ	1.17	1.20	0.92	0.81	1.18	1.37	0.94	0.85	1.19	1.36	0.94	0.85	1.20	1.48	0.96	0.88
NM	0.46	0.45	0.57	0.37	0.46	0.64	0.65	0.44	0.46	0.64	0.65	0.44	0.49	0.52	0.64	0.44
NV	0.66	0.76	0.70	0.74	0.63	0.81	0.69	0.71	0.63	0.81	0.69	0.71	0.62	0.74	0.67	0.73
NY	1.07	1.00	0.68	0.46	1.07	1.01	0.69	0.46	1.07	1.01	0.69	0.46	1.08	1.01	0.69	0.46
OH	0.78	0.65	0.50	0.40	0.77	0.58	0.42	0.38	0.77	0.57	0.42	0.38	0.76	0.55	0.42	0.38
OK	0.70	0.70	0.12	0.05	0.68	0.90	0.11	0.02	0.68	0.90	0.14	0.05	0.70	0.94	0.13	0.02
OR	0.64	0.32	0.17	0.04	0.56	0.33	0.17	0.04	0.56	0.33	0.17	0.04	0.61	0.33	0.17	0.04
PA	0.98	0.97	0.84	0.62	0.94	1.02	0.83	0.65	0.96	1.01	0.83	0.65	0.98	1.08	0.83	0.65
RI	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
SC	0.96	0.74	0.68	0.61	0.77	0.80	0.59	0.49	0.76	0.80	0.59	0.49	0.90	0.76	0.59	0.50
SD	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
TL	1.31	1.31	0.00	0.00	1.31	0.40	0.00	0.00	1.31	0.39	0.00	0.00	1.31	0.36	0.00	0.00
TN	1.17	0.50	0.41	0.32	1.17	0.55	0.41	0.31	1.17	0.56	0.40	0.31	1.18	0.46	0.37	0.28
TX	1.29	1.09	0.74	0.66	1.26	1.05	0.64	0.57	1.26	1.05	0.64	0.57	1.28	1.09	0.66	0.58
UT	1.20	1.26	1.23	1.21	1.15	1.21	1.12	1.14	1.16	1.21	1.12	1.14	1.15	1.20	1.14	1.15
VA	0.95	0.94	0.69	0.53	0.89	0.87	0.64	0.45	0.89	0.87	0.65	0.45	1.00	0.90	0.64	0.48
VT	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
WA	1.39	1.77	1.78	1.65	1.36	1.77	1.80	1.68	1.36	1.77	1.80	1.68	1.36	1.75	1.79	1.74
WI	0.66	0.59	0.43	0.33	0.66	0.62	0.46	0.34	0.66	0.62	0.46	0.34	0.66	0.63	0.46	0.34
WV	1.14	0.81	0.08	0.02	1.15	0.35	0.08	0.02	1.17	0.35	0.09	0.02	1.15	0.35	0.08	0.02
WY	1.24	1.41	1.56	0.93	1.24	1.50	1.59	0.98	1.24	1.49	1.59	0.98	1.24	1.51	1.56	0.96

*TL = tribal lands

**Scaling factors of 1.00 were applied to tags that had less than 100 tpy emissions assigned in the original source apportionment modeling. Any emissions changes in that state were assigned to a nearby state. For primary $PM_{2.5}$, the following emissions change assignments were applied: DC → MD, NH → ME, RI → CT, SD → ND, VT → NY

A.4 Air Quality Surface Results

The spatial fields of baseline AS-MO3 and Annual Average $PM_{2.5}$ in 2028, 2030, 2035, and 2040 are presented in Figure A-6 through Figure A-13. 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 A-10 through Figure A-13 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 A-6 through Figure A-13 also present the model-predicted air quality changes between the baseline and the three illustrative scenarios in 2028, 2030, 2035, and 2040 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 A-10 through Figure A-13, 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.

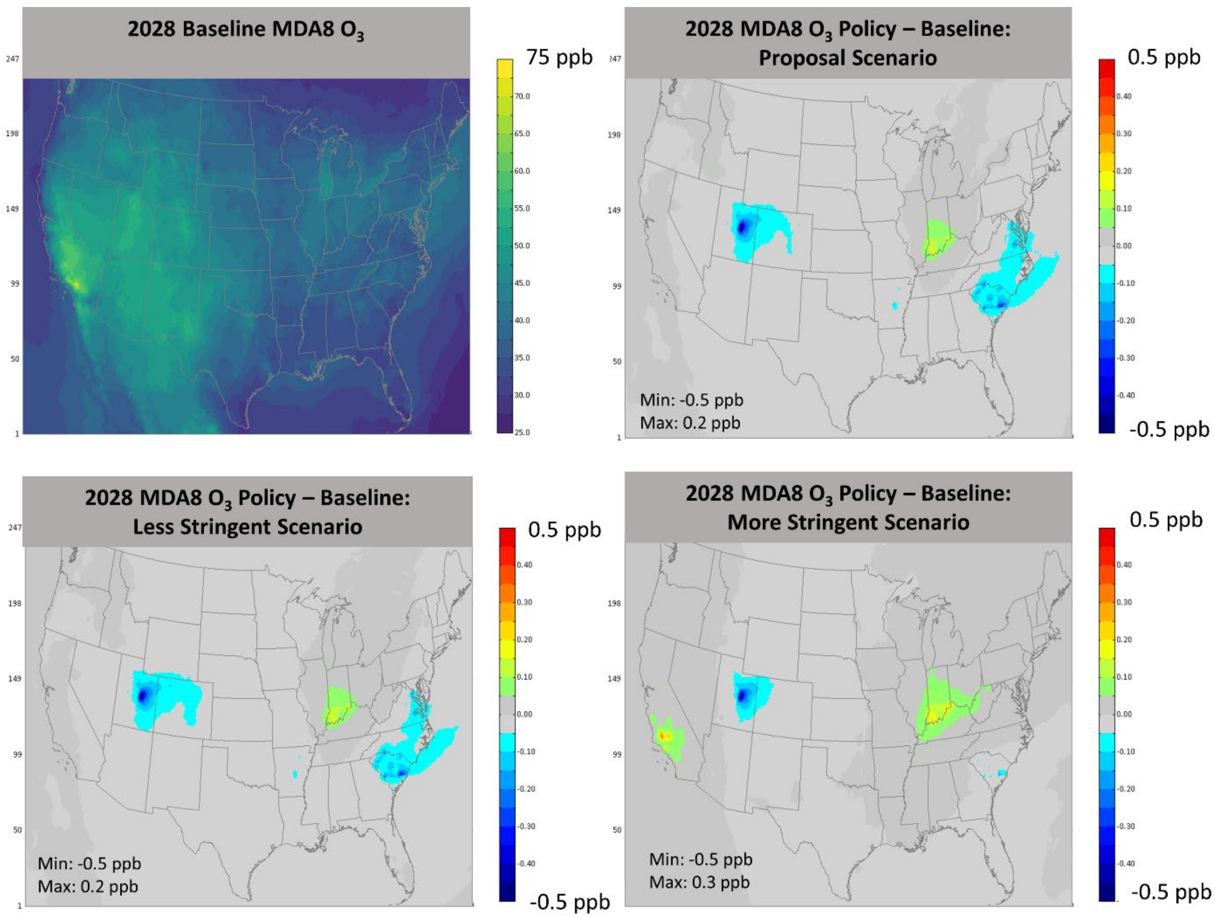

Figure A-6 Maps of ASM-O3 in 2028

Note: Baseline ozone concentrations (ppb) shown in upper left. Change in ozone in the proposal scenario compared to baseline values (ppb) shown in upper right. Change in ozone in the less stringent scenario compared to baseline values (ppb) shown in lower left. Change in ozone in the more stringent scenario compared to baseline values shown in lower right (ppb).

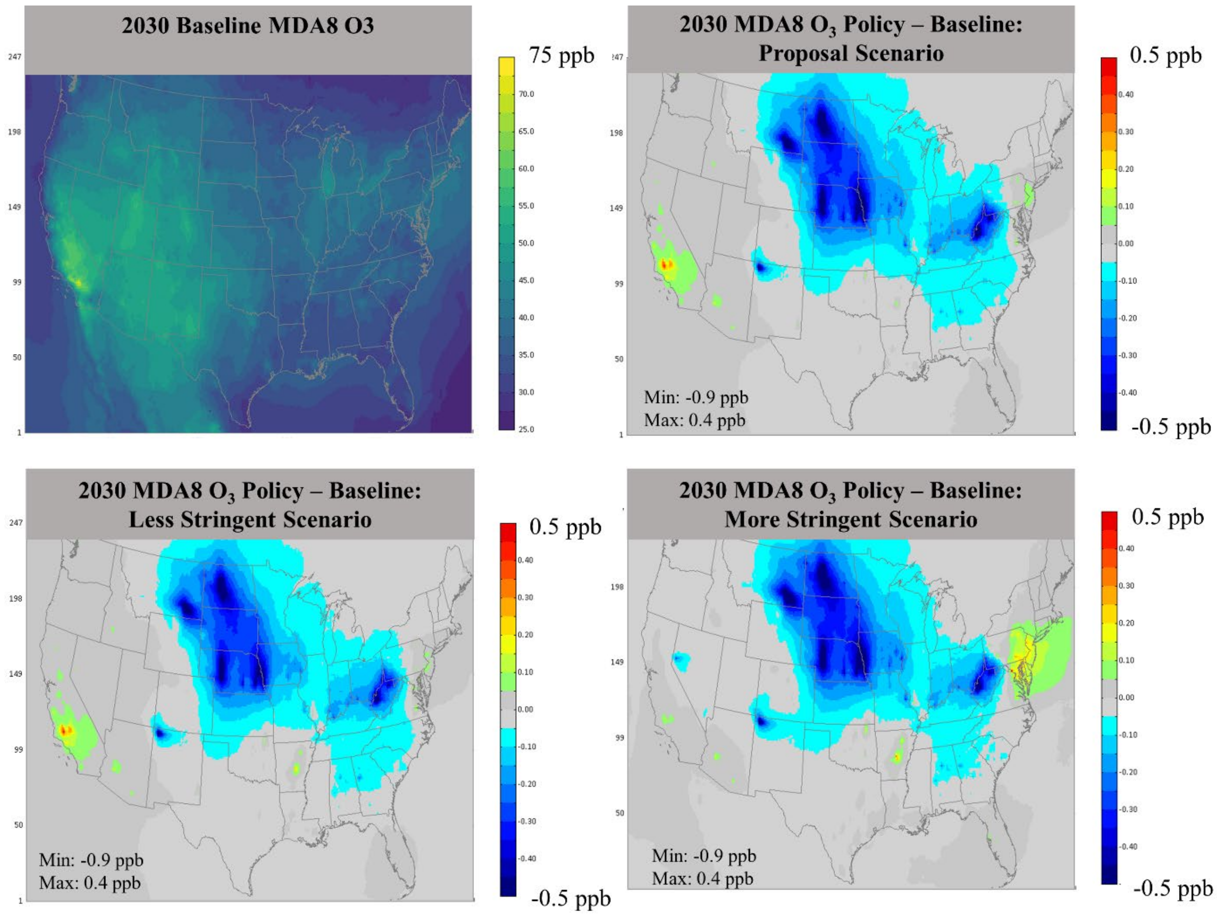

Figure A-7 Maps of ASM-O3 in 2030

Note: Baseline ozone concentrations (ppb) shown in upper left. Change in ozone in the proposal scenario compared to baseline values (ppb) shown in upper right. Change in ozone in the less stringent scenario compared to baseline values (ppb) shown in lower left. Change in ozone in the more stringent scenario compared to baseline values shown in lower right (ppb).

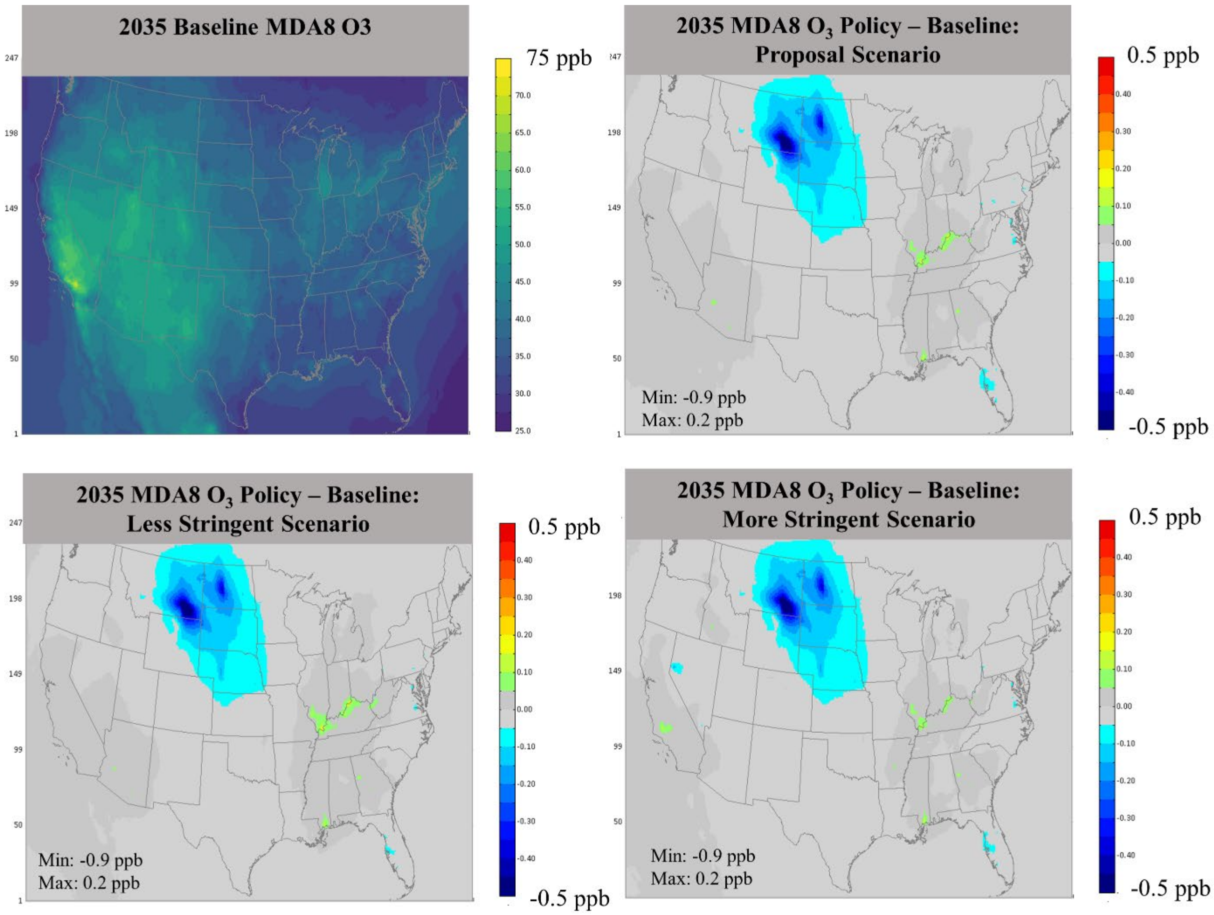

Figure A-8 Maps of ASM-O3 in 2035

Note: Baseline ozone concentrations (ppb) shown in upper left. Change in ozone in the proposal scenario compared to baseline values (ppb) shown in upper right. Change in ozone in the less stringent scenario compared to baseline values (ppb) shown in lower left. Change in ozone in the more stringent scenario compared to baseline values shown in lower right (ppb).

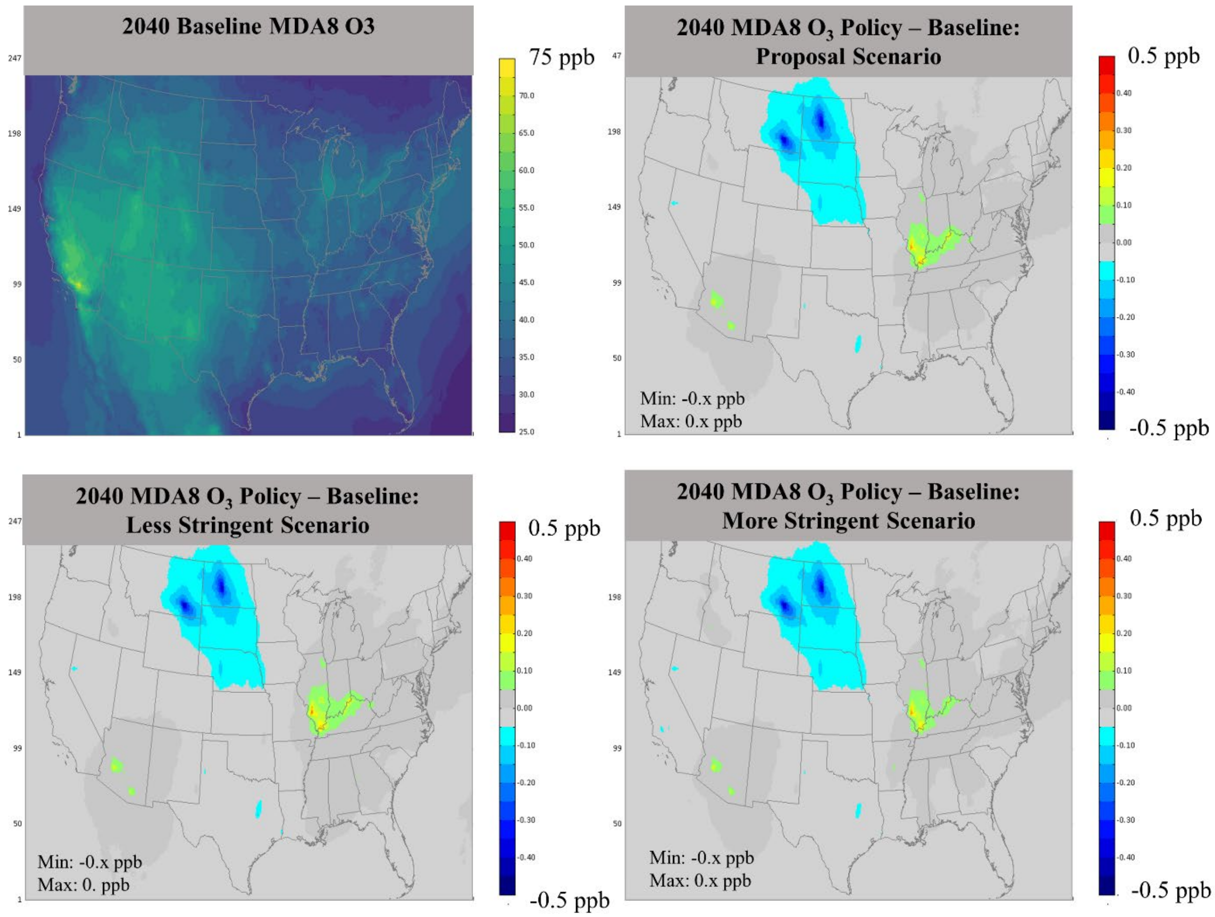

Figure A-9 Maps of ASM-O3 in 2040

Note: Baseline ozone concentrations (ppb) shown in upper left. Change in ozone in the proposal scenario compared to baseline values (ppb) shown in upper right. Change in ozone in the less stringent scenario compared to baseline values (ppb) shown in lower left. Change in ozone in the more stringent scenario compared to baseline values shown in lower right (ppb).

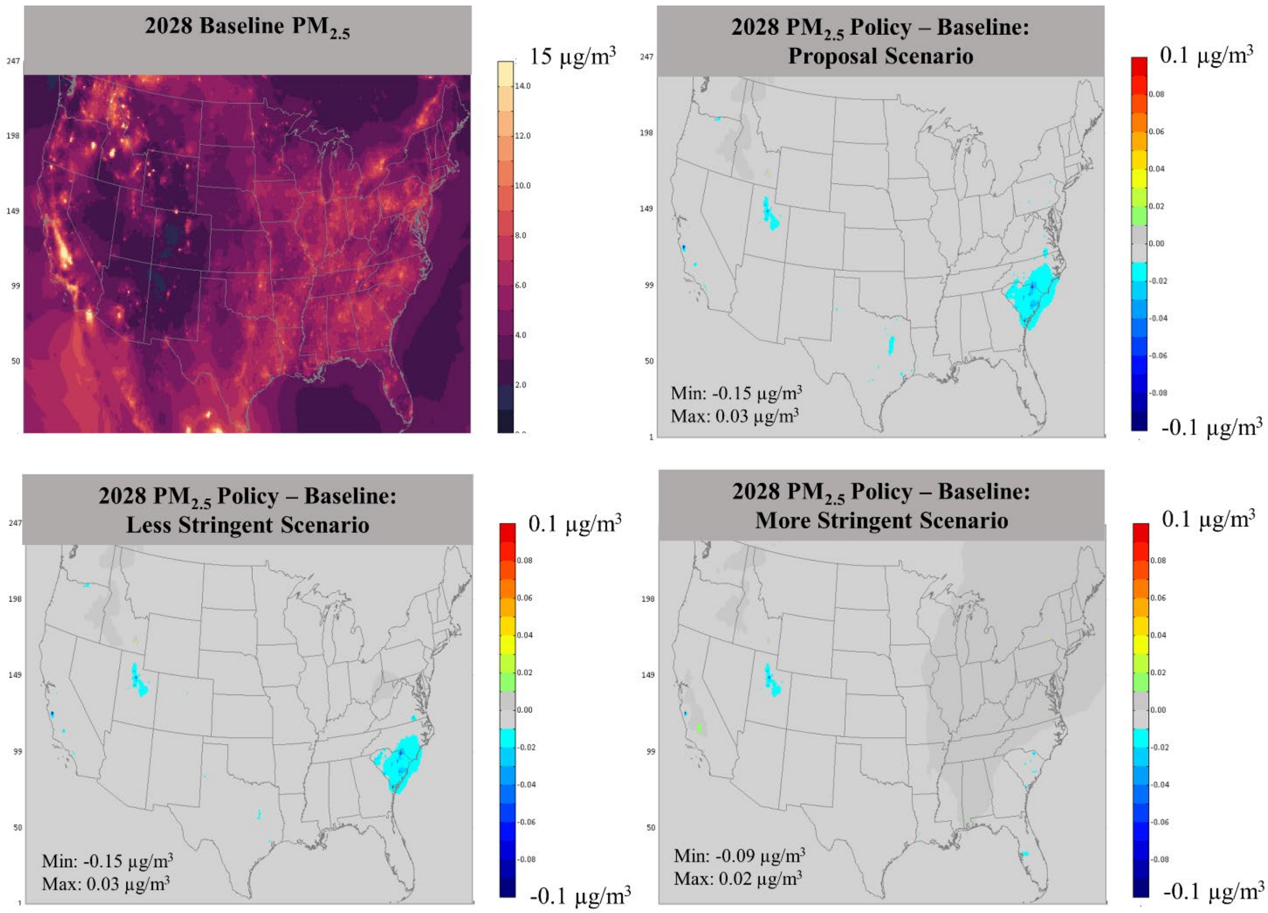

Figure A-10 Maps of $PM_{2.5}$ in 2028

Note: Baseline $PM_{2.5}$ concentrations (μg/m^3) shown in upper left. Change in $PM_{2.5}$ in the proposal scenario compared to baseline values (μg/m^3) shown in upper right. Change in $PM_{2.5}$ in the less stringent scenario compared to baseline values (μg/m^3) shown in lower left. Change in $PM_{2.5}$ in the more stringent scenario compared to baseline values shown in lower right (μg/m^3).

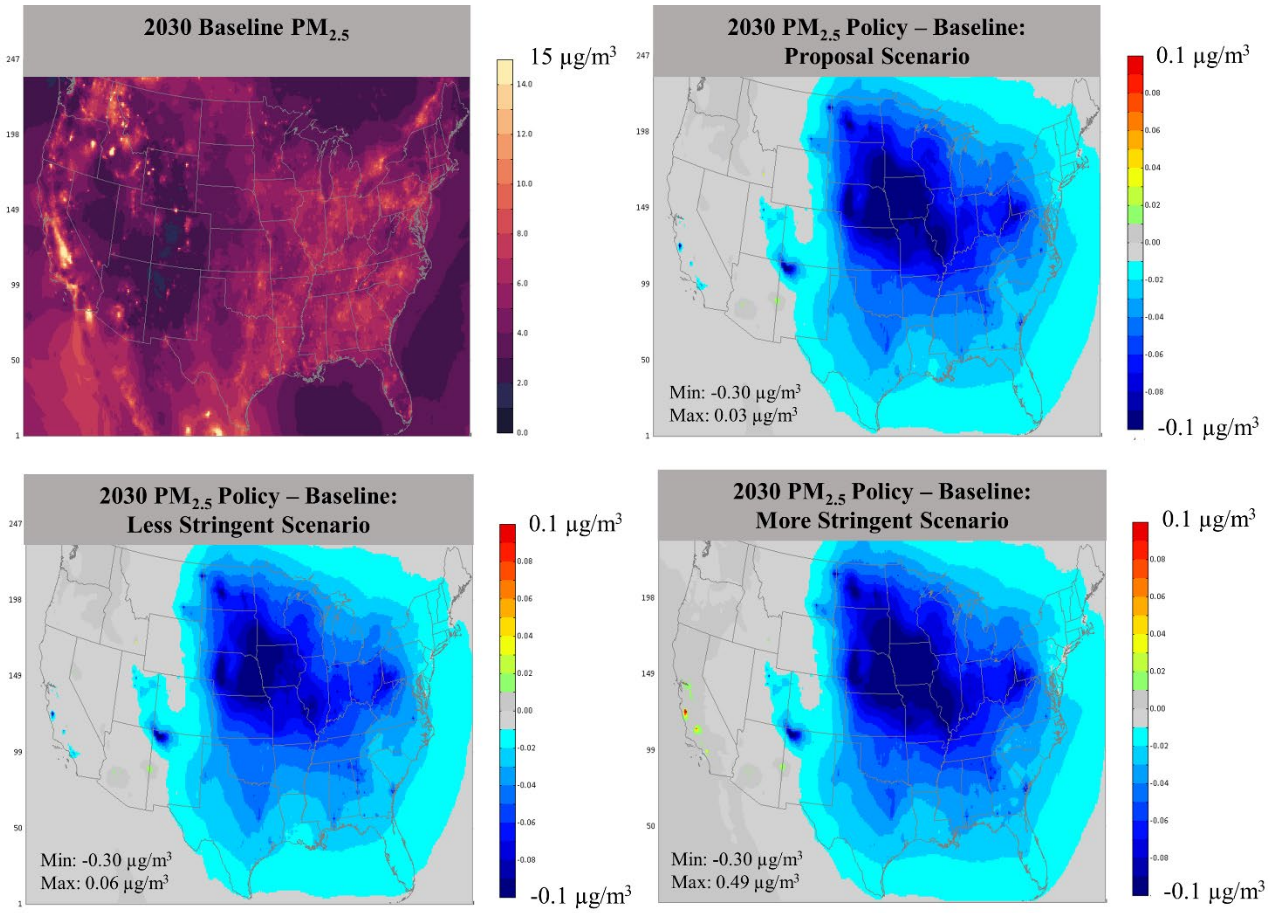

Figure A-11 Maps of $PM_{2.5}$ in 2030

Note: Baseline $PM_{2.5}$ concentrations (µg/m^3) shown in upper left. Change in $PM_{2.5}$ in the proposal scenario compared to baseline values (µg/m^3) shown in upper right. Change in $PM_{2.5}$ in the less stringent scenario compared to baseline values (µg/m^3) shown in lower left. Change in $PM_{2.5}$ in the more stringent scenario compared to baseline values shown in lower right (µg/m^3).

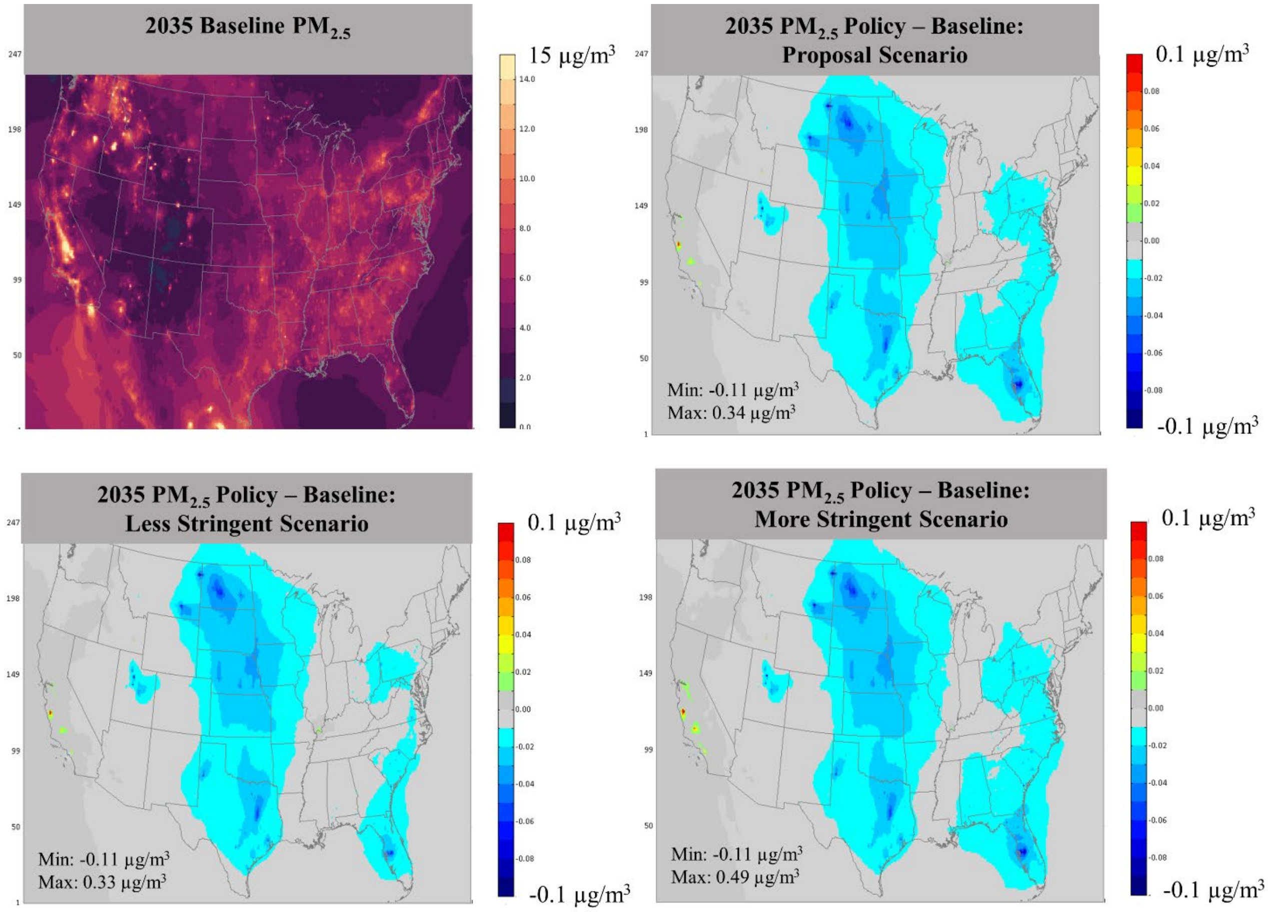

Figure A-12 Maps of $PM_{2.5}$ in 2035

Note: Baseline $PM_{2.5}$ concentrations (μg/m^3) shown in upper left. Change in $PM_{2.5}$ in the proposal scenario compared to baseline values (μg/m^3) shown in upper right. Change in $PM_{2.5}$ in the less stringent scenario compared to baseline values (μg/m^3) shown in lower left. Change in $PM_{2.5}$ in the more stringent scenario compared to baseline values shown in lower right (μg/m^3).

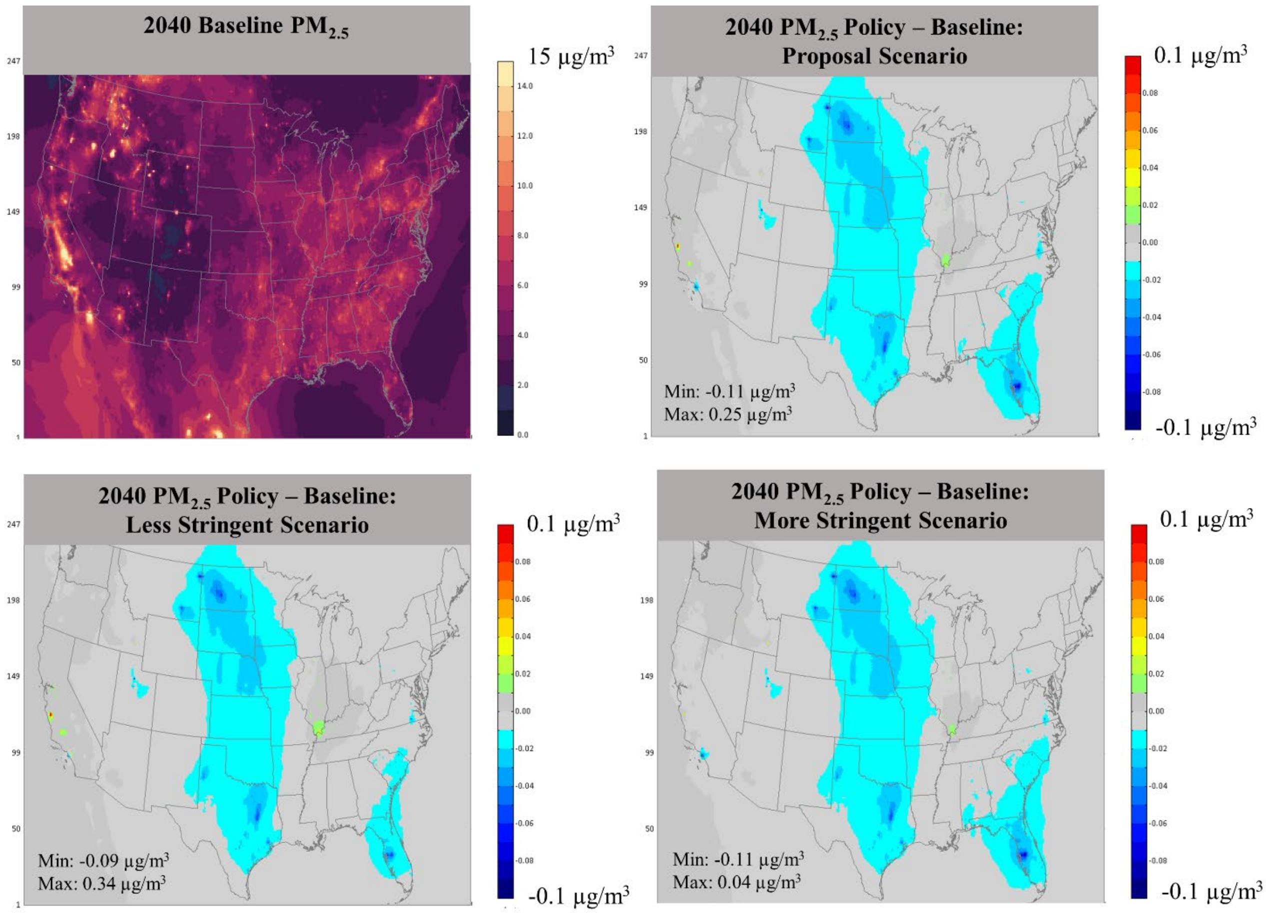

Figure A-13 Maps of $PM_{2.5}$ in 2040

Note: Baseline $PM_{2.5}$ concentrations (µg/m³) shown in upper left. Change in $PM_{2.5}$ in the proposal scenario compared to baseline values (µg/m³) shown in upper right. Change in $PM_{2.5}$ in the less stringent scenario compared to baseline values (µg/m³) shown in lower left. Change in $PM_{2.5}$ in the more stringent scenario compared to baseline values shown in lower right (µg/m³).

A.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 2026 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 2026 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 between the 2026 modeled case and the baseline and illustrative scenarios analyzed in this RIA. Finally, the 2026 CAMx-modeled concentrations themselves have some uncertainty. While all models have some level of inherent uncertainty in their formulation and inputs, the base-year 2016 model outputs have been evaluated against ambient measurements and have been shown to adequately reproduce spatially and temporally varying concentrations (U.S. EPA, 2022a, 2023).

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APPENDIX B: ECONOMY-WIDE SOCIAL COSTS AND ECONOMIC IMPACTS

B.1 Economy-Wide Modeling

This appendix analyzes the potential economy-wide impacts of the proposed rules using a computable general equilibrium (CGE) model.[185] 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.

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).[186] 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.

[185] Appendix B pertains to the analysis of the proposed standards for new natural gas-fired EGUs and for existing coal-fired EGUs. Please see Section 8 for impact analysis of the proposed standards for existing natural gas-fired EGUs and the third phase of the proposed standards for new natural gas-fired EGUs.

[186] 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).

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 provides 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.[187] Model version v2.1.0 of SAGE is used in this analysis.

B.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.[188] For example, the model estimates 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 et al., 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.

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 B-1 uses a simplified circular flow diagram to depict how input and output markets are generally connected to each other in

[187] 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 is incomplete and needs to be augmented with traditional benefits analysis to develop measures of net benefits.

[188] 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 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).

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.

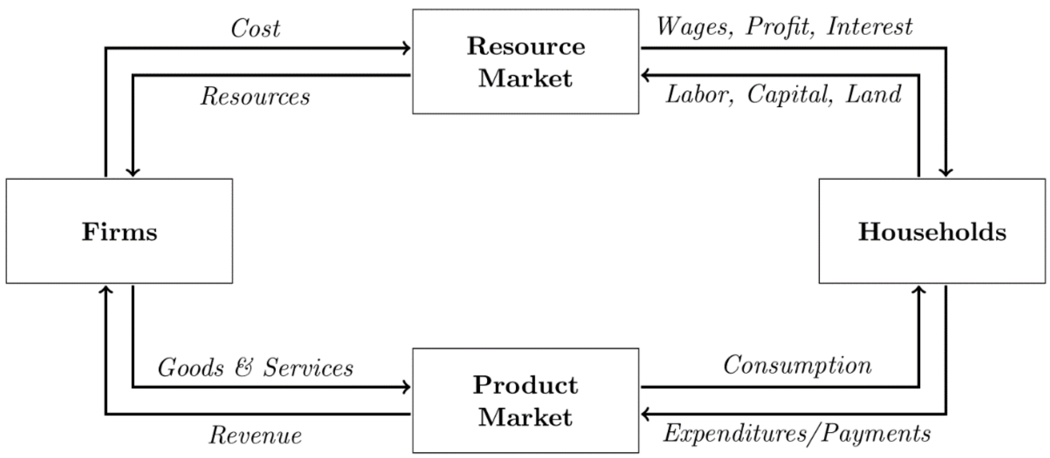

Figure B-1 Depiction of the Circular Flow of the Economy

The SAGE model includes explicit subnational regional representation within the United States 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 B-1). 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 B-1 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.[189] 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.[190] These data are combined with key behavioral parameters for firms and households that are adopted

[189] 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).

[190] 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.[191] 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 (v2.1.0), 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.[192]

B.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 economy-wide social costs - the sum of all opportunity costs that result from the regulation in the present and future – may differ from the partial equilibrium estimate of costs depending on whether there are significant cross-price effects and interactions with other pre-existing market distortions elsewhere in the economy. The economy-wide measure of social costs may also differ

[191] 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
[192] https://www.epa.gov/environmental-economics/cge-modeling-regulatory-analysis

when demand-side effects are not captured in the partial equilibrium measure or transfer payments are not netted out of the partial equilibrium measure. 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 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.

B.3.1 Overview of Linking Methodology

To model the economy-wide effects of the proposed rules, we calibrate the SAGE model inputs that represent the impact of the proposed rules such that sectoral costs in a corresponding partial equilibrium sub-model of SAGE (called SAGE-PE) align with the partial equilibrium incremental costs derived from the technology-rich IPM. This approach of aligning partial equilibrium incremental costs between the two models allows us to avoid confounding the estimate of economy-wide effects with differences in the models' partial equilibrium representations of sectors shared by both IPM and SAGE.[193] Care is given in translating IPM outputs for use in SAGE so that the two models adequately capture equivalent partial equilibrium costs.[194]

Figure B-2 provides an overview of the approach leveraging the IPM results to introduce the incremental costs of the proposed 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

[193] 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."

[194] 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.

aligning model years, distributing IPM costs to SAGE model inputs (by fuel, other materials, 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 proposed 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 partial equilibrium 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.

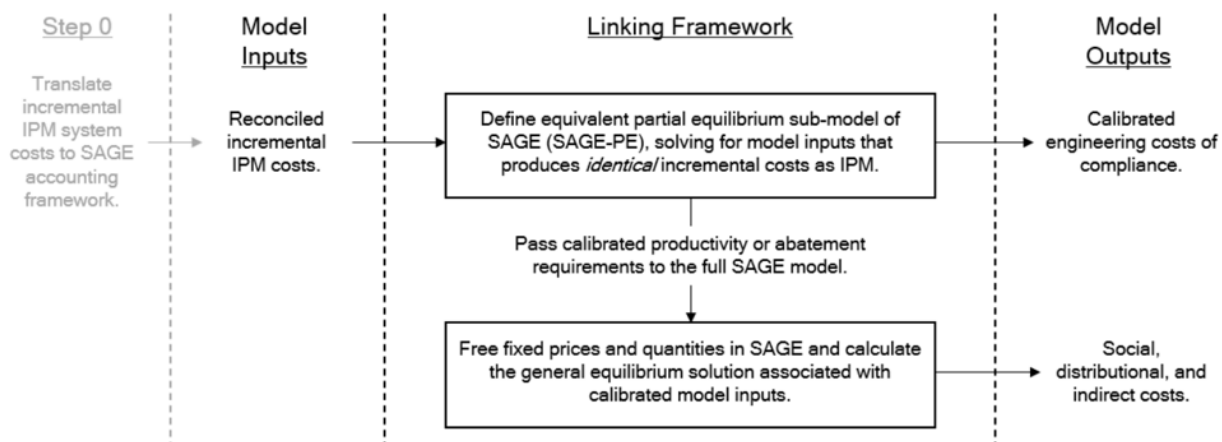

Figure B-2 Hybrid Linkage Approach for IPM and SAGE

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 et al., 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.

To align SAGE with IPM, the productivity shock is calibrated so that the incremental 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 proposed 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, where model years 2026 and beyond are endogenously determined. See Schreiber et al. (2023) for more details on the linking approach.

B.3.2 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 B-2 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 capital flow 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 capital flow 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 B-2 IPM Cost Outputs

Time Periods	Cost Categories	IPM Regions	Generator Vintage
2028 2030-2055 (5-year time steps)	Overnight capital costs Annualized 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;[195] (2) mapping IPM regions to SAGE regions; (3) splitting

[195] 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.

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; (7) mapping the input requirements of hydrogen based on engineering assessments by NREL (2022),[196] and (8) 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.

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 capital flow payments. Because the accounting for capital is different between models, the former approach can lead to significant differences in capital flow payments between models. Therefore, the second approach is used to align incremental net of tax capital flow payments when calibrating the productivity shock. Because the representation of capital is different between the models, differences in induced investment in the capital stock from targeting consistent capital flow 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, production, and fuel subsidies (i.e., ITC/PTC, 45Q and 45V). The SAGE-PE model is calibrated to match both the real resource requirements for the expected compliance pathway

[196] SAGE models an aggregate chemical manufacturing sector with a cost structure likely significantly different than the costs of producing hydrogen, specifically. Therefore, we use information on production costs from NREL (2022) to define the additional input requirements to SAGE in response to hydrogen use in the policy case in IPM. Mapping NREL (2022) to SAGE inputs, we find cost shares for hydrogen are 51 percent for natural gas, 33 percent for capital, 6 percent for labor, 6 percent for electricity, 4 percent for transportation, and 0.02 percent for water, sewage, and other utilities.

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 proposed rules by adding them to the cost of inputs (i.e., the incremental costs are net of the subsidy payments).[197] To avoid overstating price impacts and social costs, 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 proposed rules. Additional features of the IRA are not explicitly represented in SAGE at this time.

B.4 Results

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

B.4.1 Economy-wide Social Costs

Table B-3 presents the economy-wide, general equilibrium social costs from the proposed 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 proposed rules, setting aside health, climate, and other benefits (quantified elsewhere in the RIA). For comparison, Table B-3 also presents the partial equilibrium private costs estimated to

[197] ITC/PTC and 45Q subsidies are levied on capital whereas the 45V subsidy is shared amongst hydrogen producing inputs according to NREL (2022). We assume that changes in ITC/PTC subsidies are zero after 2042.

be paid by the electricity sector by IPM inclusive of subsidy payments from the IRA but less taxes and transfers and mapped to the SAGE model years. For both the partial equilibrium private costs and the general equilibrium social costs, Table B-3 presents the present value and annualized costs for the period of 2026 to 2046.

The general equilibrium social costs differ from the partial equilibrium private costs 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 proposed 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 annualized social costs estimated in SAGE are approximately 35 percent larger than the partial equilibrium private compliance costs (less taxes and transfers). This is consistent with general expectations based on the empirical literature (Marten et al., 2019). However, we note that the social cost estimate reflects the combined effect of the proposed rules' requirements and interactions with IRA subsidies for specific technologies that are expected to see increased use in response to the proposed rules. We are not able to identify their relative roles at this time. Finally, we note that, while the partial equilibrium private compliance costs peak in the 2031 SAGE model year, aggregate social costs are spread out more evenly over the model time horizon as the economy smooths out the impact.

Table B-3 Social Costs (billions of 2019 dollars)

SAGE Model Year	Partial Equilibrium Private Costs (Less Taxes and Transfers)	General Equilibrium Social Costs
2026	-0.27	1.06
2031	3.43	1.18
2036	-0.27	1.27
2041	0.35	1.37
2046	-0.32	1.48
Present Value (2026 to 2046)	12.6	17.4
Equivalent Annualized Value	0.9	1.2

Notes: Social costs are calculated as equivalent variation. Present value and annualized cost estimates are based on linearly interpolating costs between model years and are based on the internal discount rate in SAGE of 4.5 percent.

B.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 B-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 proposed rules are estimated to increase GDP in 2026 by 0.018 percent due to increases in investment, but subsequently result in a modest decrease in GDP with a peak reduction of 0.024 percent in 2031. 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).[198]

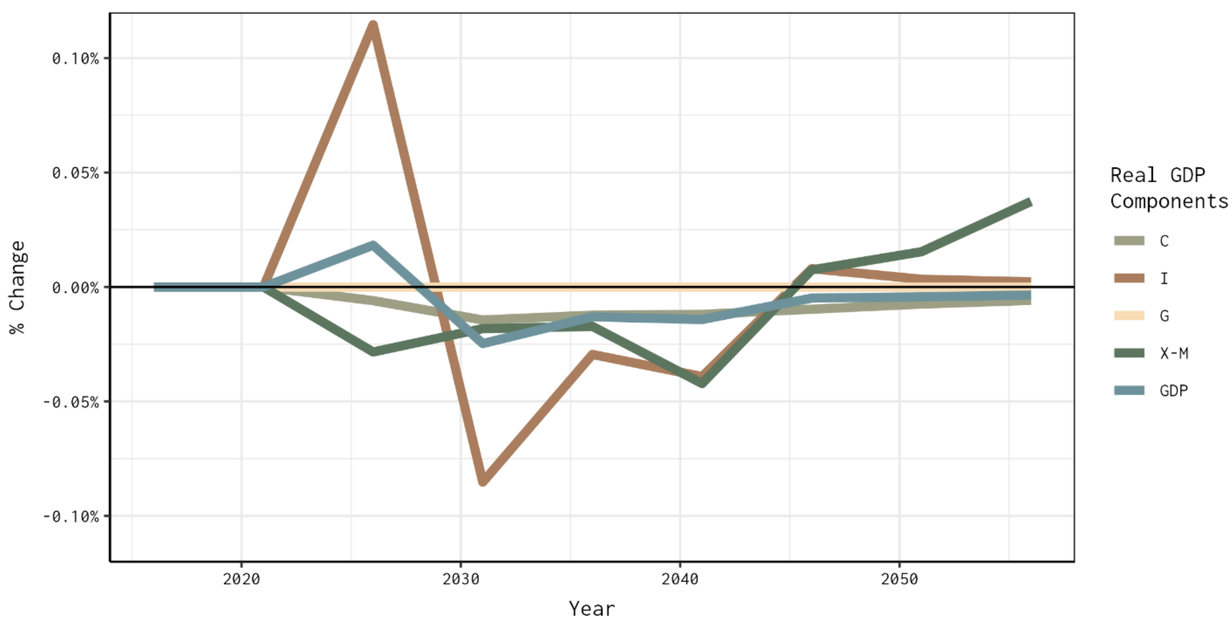

Figure B-3 Percent Change in Real GDP and Components

Figure B-3 also reports changes in the components of GDP from the expenditure side. The proposed rules are expected to accelerate investments in the electricity sector, leading to a

[198] "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" (U.S. EPA Science Advisory Board, 2017)

net increase in aggregate investment in 2026 (0.114 percent) 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 proposed rules, shifting some purchases towards imports, though the effect is expected to dissipate over time.

B.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 proposed rules affect input demand in other sectors of the economy and 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 B-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 price. 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). The changes in output from the natural gas sector reflect both changes in the direct use of natural gas by the electricity sector and changes in its use in hydrogen production, in addition to other economy-wide changes in demand in response to price changes.

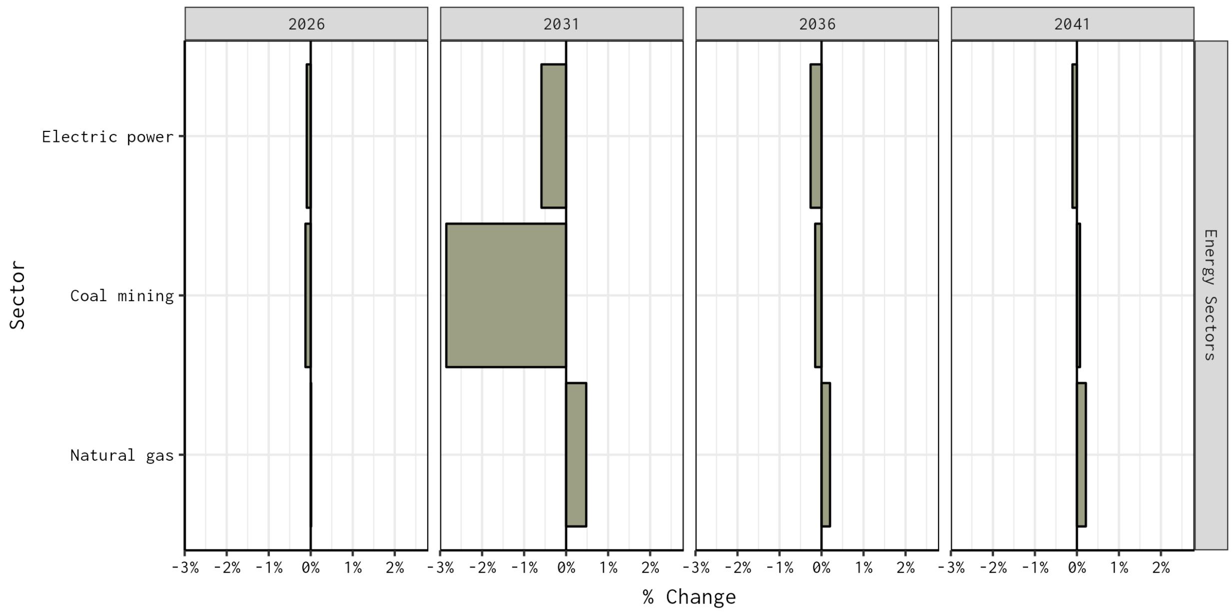

Figure B-4 Percent Change in Sectoral Output (Electricity, Coal, Natural Gas)

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 B-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 B-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 proposed rules.

Combining output impacts across all sectors in the economy, Figure B-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 0.018 percent in 2026, with declines of similar magnitude in subsequent years. The model suggests modest increases in production in 2026 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.

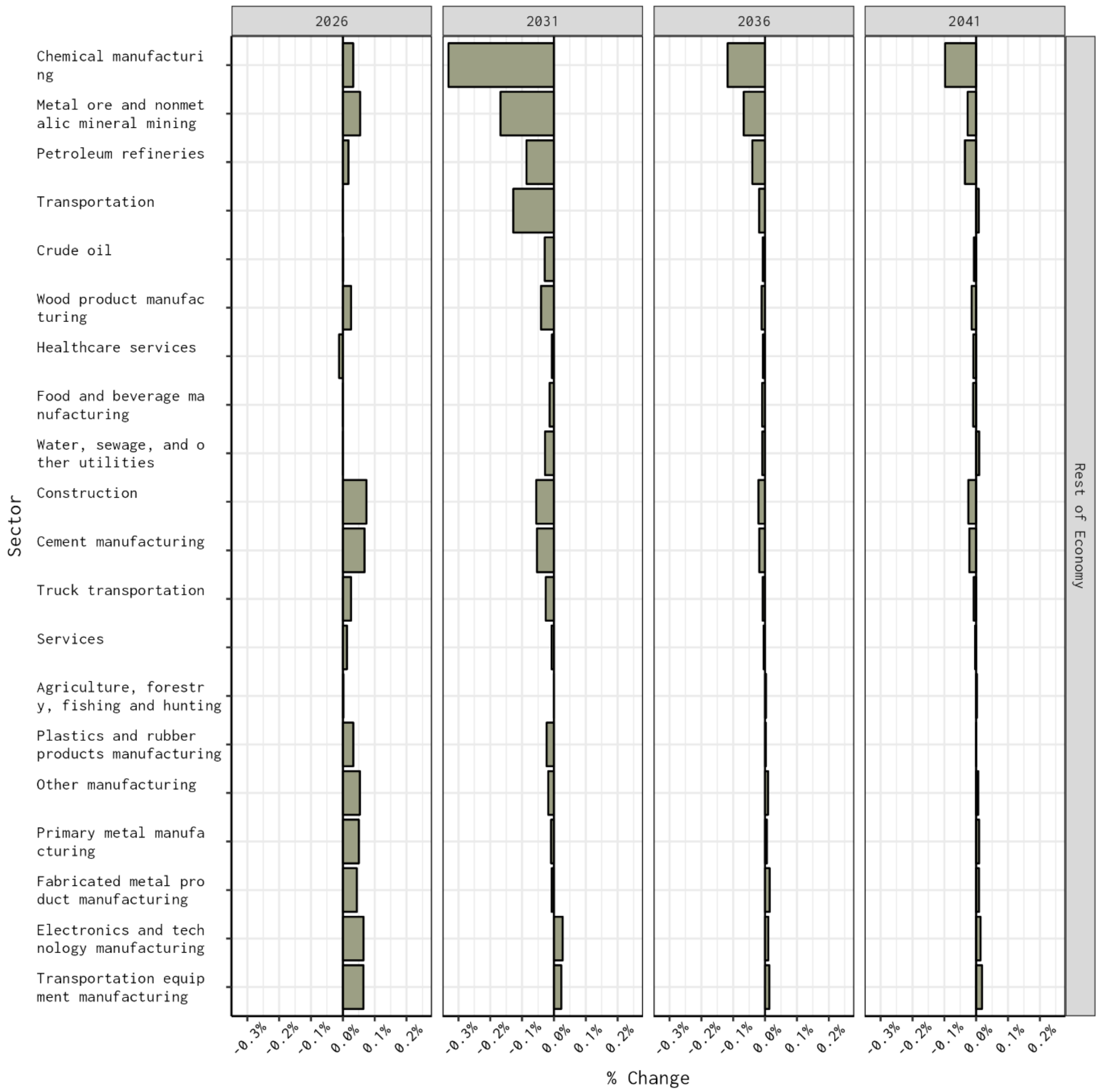

Figure B-5 Percent Change in Sectoral Output (Rest of Economy)

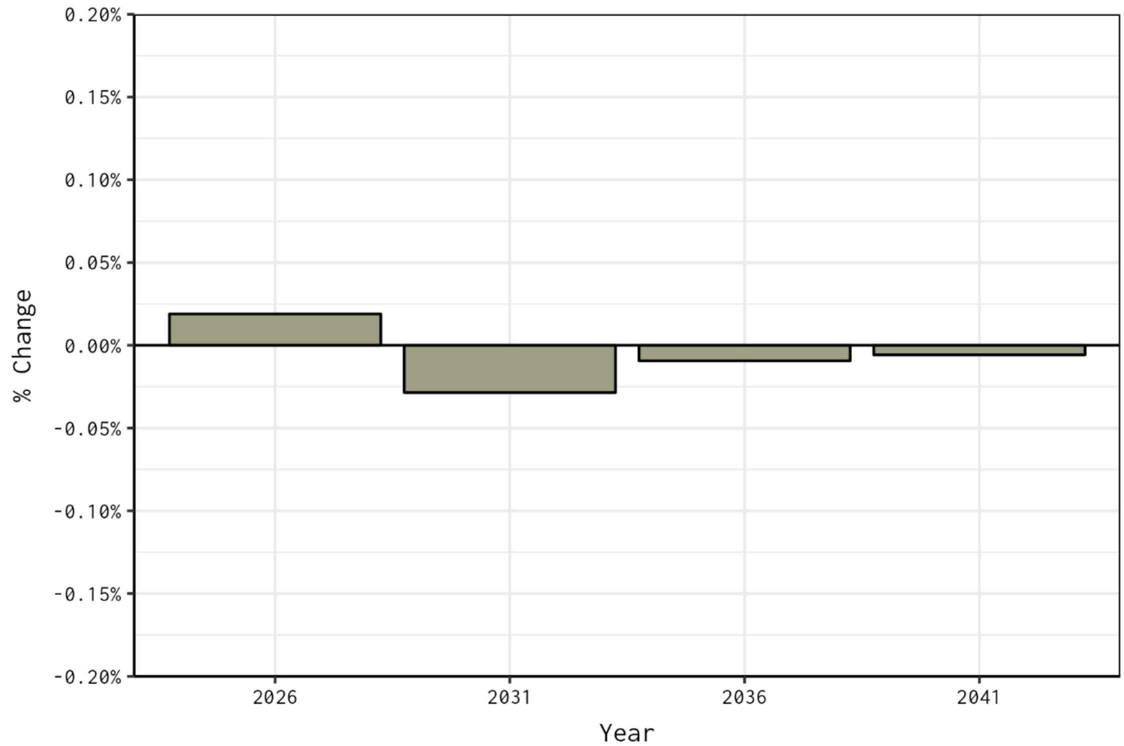

Figure B-6 Percent Change in Economy-wide Sectoral Output (All Sectors)

B.4.4 Output Price Impacts

Figure B-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.[199] The largest percent changes in real output prices occur in the natural gas, electricity, and coal sectors. The estimated natural gas price change is due to the net effect of both increased demand in the electricity sector (for direct use and for the production of hydrogen) as well as reductions in demand elsewhere in the economy as the price is bid upwards. The estimated change in the electricity sector output price reflects the additional costs associated with complying with the proposed rules as well as demand side reductions in electricity use from both firms and households. Estimated price decreases for coal reflect the reduced demand for the fuel in the electricity sector.

[199] 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).

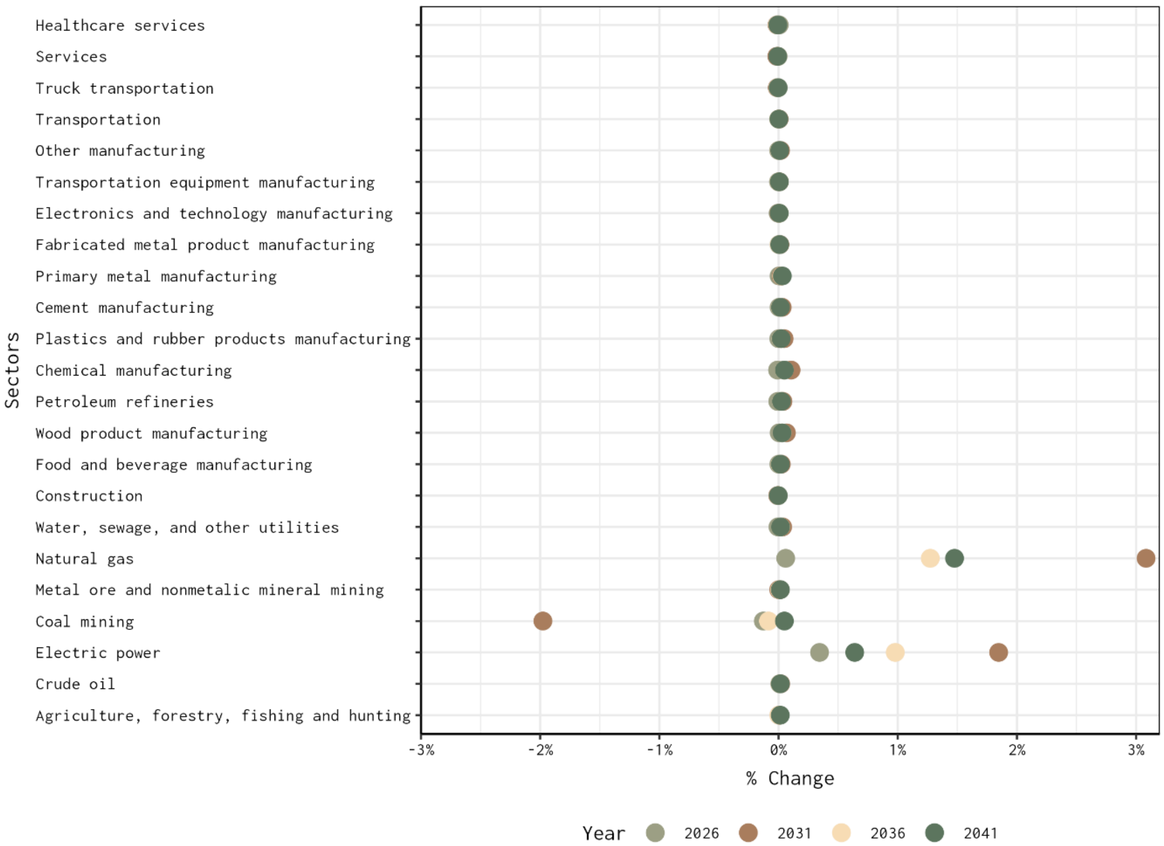

Figure B-7 Percent Change in Real Output Prices

B.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 analyzing the medium to long run changes in the expected use of labor across sectors as a result of the proposed rules.

While the model 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. 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 B-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 year 2026, 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 proposed regulatory requirements. In subsequent model years expected reductions in output and investment result in small decreases in labor supply. Figure B-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 B-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 is driven by increases in demand for labor in sectors associated with capital formation (e.g., construction, cement manufacturing) to support new investments.

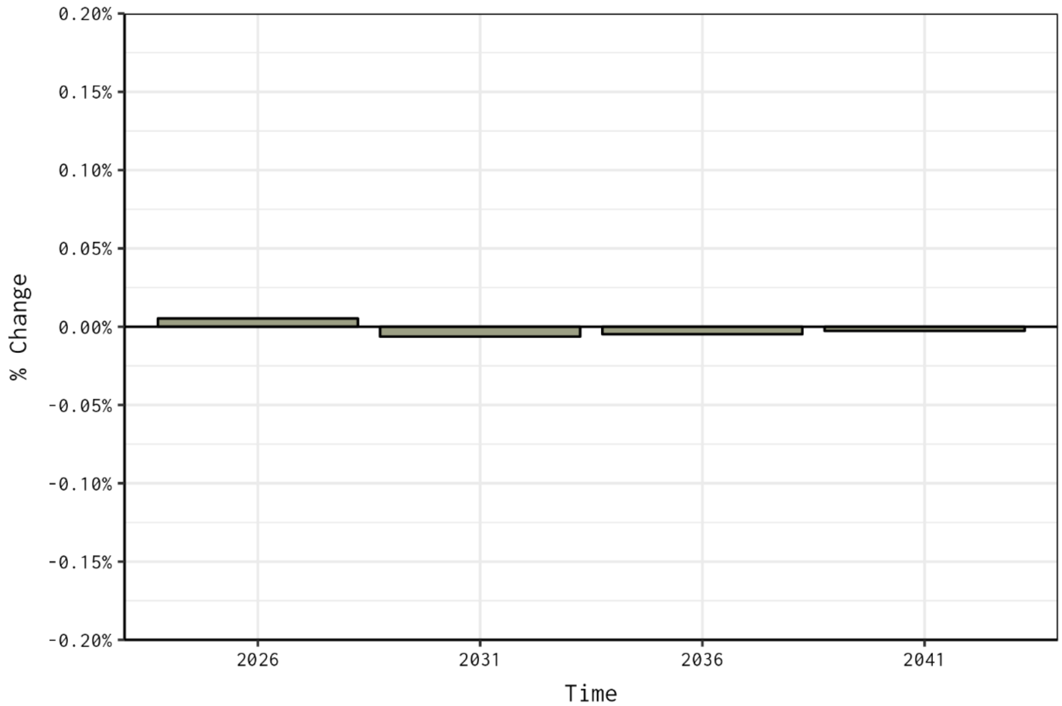

Figure B-8 Percent Change in Economy-wide Labor Demand (All Sectors)

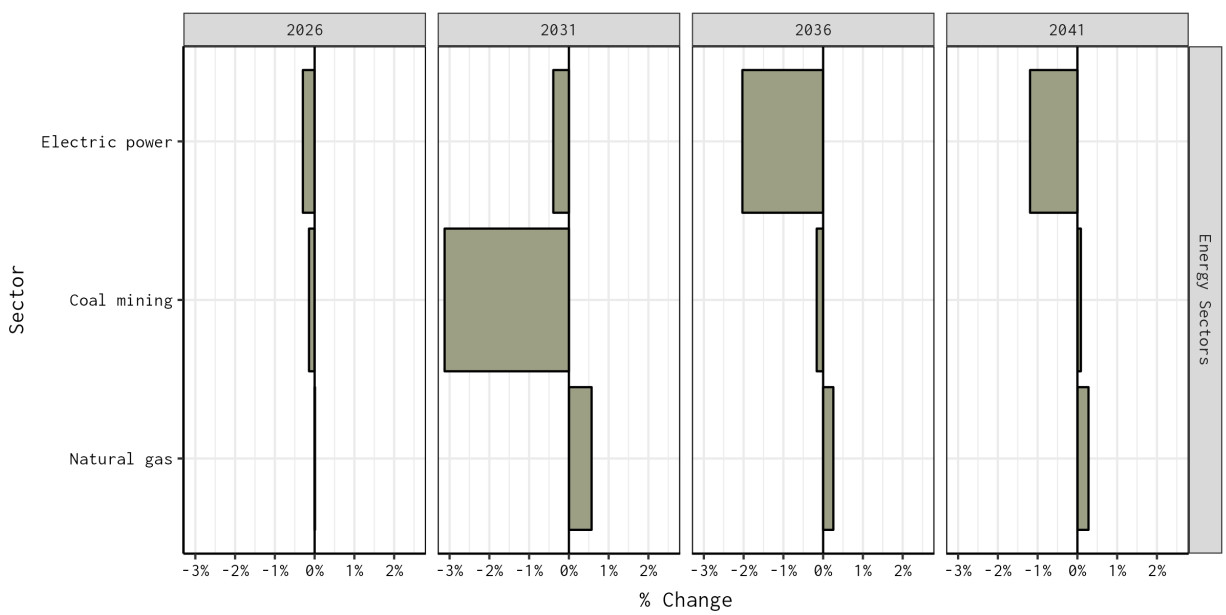

Figure B-9 Percent Change in Labor Demand (Electricity, Coal, Natural Gas)

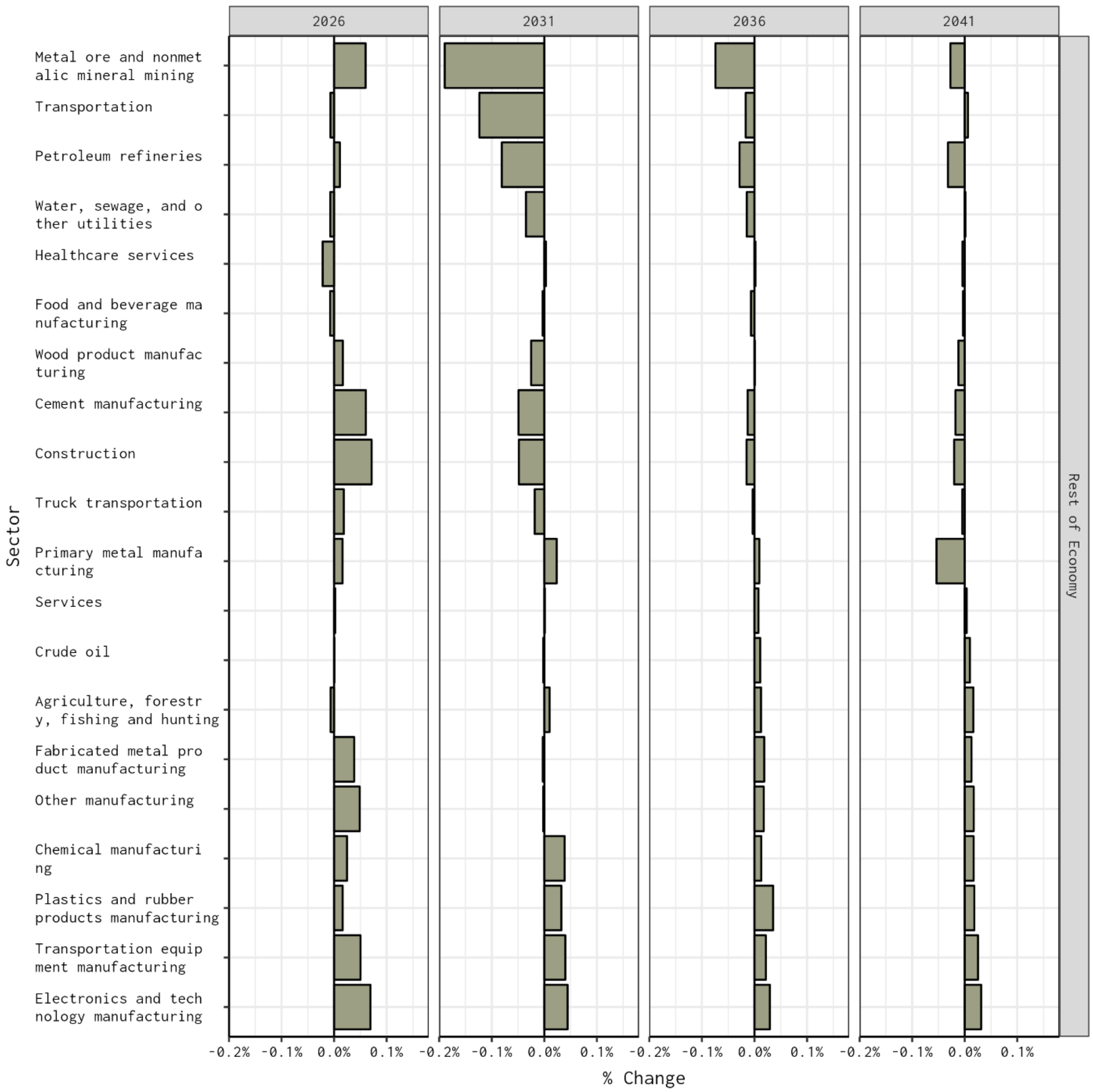

Figure B-10 Percent Change in Labor Demand (Rest of Economy)

B.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 B-11.[200] 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.

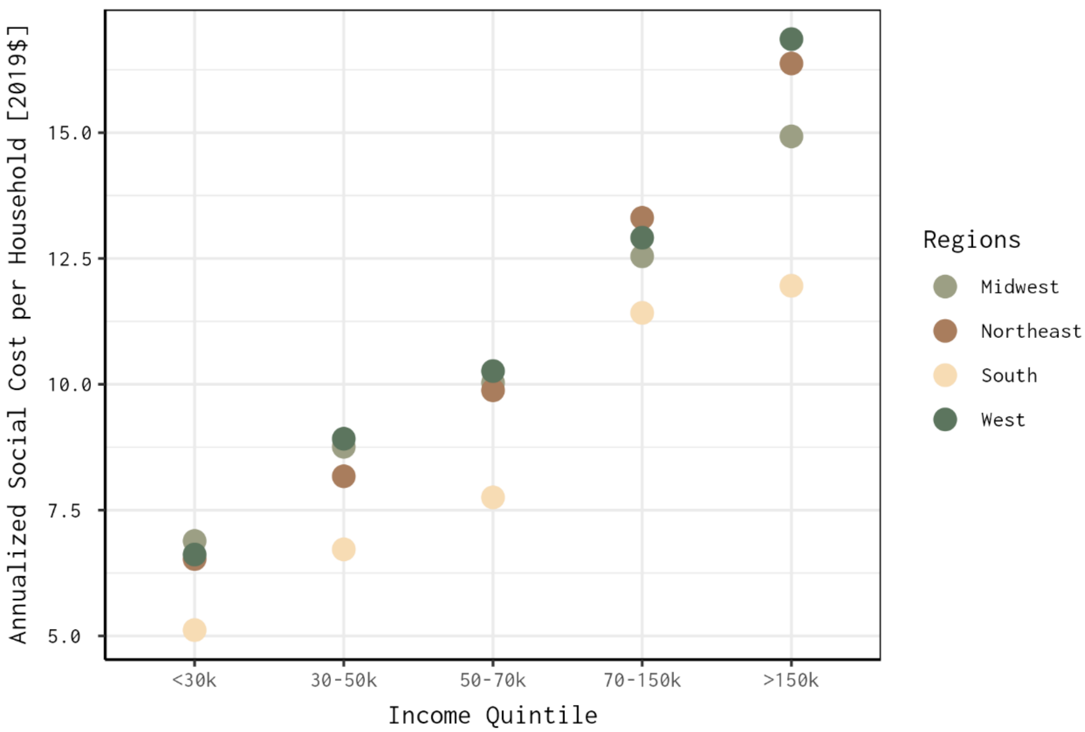

Figure B-11 Distribution of General Equilibrium Social Costs

Estimates in Figure B-11 reflect a combined effect of the proposed rules' requirements and interactions with IRA subsidies that are expected to see increased use in response to the proposed 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 non-distortionary approach to closing the model. This is the approach used in

[200] Distributional cost estimates are annualized for the period 2026 to 2046 and divided by the total number of households of a given income quintile and region using 2016 estimates from the Census' Current Population Survey.

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.

B.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 proposed rules. However, both the use of SAGE in a regulatory analysis and the framework for linking IPM with the SAGE model are subject to some uncertainty:

- 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, interactions that the proposed rules may have with compliance activities already underway to meet existing regulatory requirements may not be explicitly captured in SAGE.
- 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 proposed 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 capital flow payments. However, because the representation of capital differs between IPM and SAGE, the projected stream of capital investments in response to the proposed rules also likely differs between the two models. See Appendix B.3.2 for a discussion of this choice.

- This analysis attributes all compliance costs for existing generators in IPM to production with extant capital in the SAGE model. Extant capital in SAGE is assumed to be relatively inflexible in its ability to accommodate changes in production processes when compared to new capital. 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. Given these differences, it is possible that the linked framework may overattribute 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 they interact with pre-existing distortions in the economy. Furthermore, this treatment of subsidies is subject to additional uncertainties related to the effective magnitude of the subsidy payments. The input composition assumed for the production of hydrogen, described in Appendix B.3.2, is subject to uncertainty. If the input composition for hydrogen production differs substantially from what is assumed for this analysis, it could also affect social cost estimates.
- The purpose of this analysis is to quantify the economy-wide impacts of the proposed rules. To the extent possible, the analysis models the potential interactions between the proposed rules and IRA subsidies, but it is beyond the scope of this proposal to evaluate the social cost of the IRA subsidies in their entirety. Additional effects of the IRA, as they relate to the proposed rules, beyond the specific subsidies modeled in this RIA could result in a change in estimated social costs and other economy-wide impacts.

B.6 References

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APPENDIX C: ASSESSMENT OF POTENTIAL COSTS AND EMISSIONS IMPACTS OF PROPOSED NEW AND EXISTING SOURCE STANDARDS ANALYZED SEPARATELY

C.1 Modeling the Rules Independently

In this appendix, we describe the projected EGU compliance behavior, costs, and emissions impacts for the proposed Emission Guidelines and proposed NSPS when modeled independently.[201] We also compare the results from each rule modeled individually with the results presented elsewhere in the RIA that shows the proposed 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 proposal, as outlined in Table C-1 and Table C-2.

[201] Appendix C pertains to the analysis of the proposed standards for new natural gas-fired EGUs and for existing coal-fired EGUs. Please see Section 8 for impact analysis of the proposed standards for existing natural gas-fired EGUs and the third phase of the proposed standards for new natural gas-fired EGUs.

Table C-1 Summary of GHG Mitigation Measures for Existing Sources by Source Category under the Proposal[a,b,c,d]

Affected EGUs	Subcategory Definition	GHG Mitigation Measure
Long-term existing coal-fired steam generating units	Coal-fired steam generating units without committed retirement prior to 2040	CCS with 90 percent capture of CO_2, starting in 2030
Medium-term existing coal-fired steam generating units	Coal-fired steam generating units with a committed retirement by 2040 that are less than 500 MW, and that are not a near-term/low utilization unit	Natural gas co-firing at 40 percent of the heat input to the unit, starting in 2030
Near-term existing coal-fired steam generating units	Coal-fired steam generating units with a committed retirement prior to 2035 that operate with annual capacity factors less than 20 percent in 2030	Routine methods of operation
Imminent-term existing coal-fired steam generating units	Coal-fired steam generating units without a federally enforceable retirement commitment prior to 2030	Routine methods of operation

[a] All years shown in this table reflect IPM run years.
[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 are no longer subject to coal-fired EGU mitigation measures outlined above.
[d] The modeling did not include GHG mitigation measure requirements on existing natural gas generation. These requirements are analyzed separately in Section 8.

Table C-2 Summary of GHG Mitigation Measures for New Sources by Source Category under the Proposal[a,b,c,d]

Affected EGUs	Subcategory Definition	1st Component BSER	2nd Component BSER	Second Phase Applicability: Proposal and Less Stringent Scenario
Baseload Economic NGCC Additions	NGCC units that commence construction after 2023 and operate at an annual capacity factor of more than 50%	Efficient generation	30% by volume hydrogen co-firing or CCS	2035
Intermediate Load Economic NGCC Additions	NGCC units that commence construction after 2023 and operate at an annual capacity factor of less than 50%	Efficient generation	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%	Efficient generation	48% by volume hydrogen co-firing	
Peaking Economic NGCT Additions	NGCT units that commence construction after 2023 and operate at an annual capacity factor of less than 20%	Efficient generation	Efficient generation	

[a] All years shown in this table reflect IPM run years.
[b] Delivered hydrogen price is assumed to be $0.5/kg in years in which the second phase of the NSPS is active, and $1/kg in all other years.
[c] NGCC unit additions that install CCS are no longer subject to the GHG mitigation measures outlined above.
[d] The modeling did not include GHG mitigation measure requirements on existing natural gas generation. These requirements are analyzed separately in Section 8.

C.2 Compliance Cost Assessment

The estimates of incremental costs of supplying electricity under the proposal and under the proposed Emission Guidelines and proposed NSPS when modeled separately are presented in Table C-3. Estimates for additional recordkeeping, monitoring, and reporting requirements for EGUs are also included within the estimates in this table.

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

	Proposal	Existing Source Rule Only	New Source Rule Only
2024 to 2042 (Annualized)	0.96	1.1	0.17
2024 to 2045 (Annualized)	0.86	1.1	0.18
2028 (Annual)	-0.22	-0.21	0.051
2030 (Annual)	4.1	4.0	0.13
2035 (Annual)	0.27	0.53	-0.21
2040 (Annual)	0.76	1.3	-0.64
2045 (Annual)	-0.048	0.22	-0.30

"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.[202] This does not include compliance costs beyond 2042. "2024 to 2045 (Annualized)" reflects total estimated annual compliance costs levelized over the period 2024 through 2045 and discounted using a 3.76 real discount rate. This does not include compliance costs beyond 2045. "2028 (Annual)" through "2045 (Annual)" costs reflect annual estimates in each of those run years.[203]

Existing coal-fired EGUs represent the largest share of affected resources within the proposal. Hence the existing source rule is responsible for the majority of cost increases projected under the proposed (combined effect) rule. New sources represent a smaller total share of the affected sources under this rule, and hence cost increases projected under the proposed NSPS alone are smaller than under the existing source rule. The projected new source rule costs are lower than baseline values since the delivered price of hydrogen is assumed to be $0.5/kg when the second phase of the NSPS is active (starting in 2035), and $1/kg in all other years. At this lower price assumption, hydrogen would be cost competitive under baseline conditions in some markets, resulting in lower total projected costs than under the baseline scenario which does not feature a cost decline.

C.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 C-4 presents the estimated reduction

[202] 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 21-year period (2024 to 2045) 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 2042 using 3 percent and 7 percent consistent with OMB guidance.

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

in power sector CO_2 emissions resulting from compliance with the proposed requirements, as well as the estimated emissions from the proposed Emission Guidelines and proposed NSPS independently.

The CO_2 emission reductions follow an expected pattern: the existing source rule is responsible for the majority of reductions under the proposal 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 proposal (713 million metric tons) are greater than under the existing source rule only (711 million metric tons) and under the proposed NSPS only (an increase of 23 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 through 2030. By 2035 reductions at new sources outweigh increases in emissions 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 C-4 EGU Annual CO_2 Emissions and Emissions Changes (million metric tons) for the Baseline and the Illustrative Scenarios from 2028 to 2045[204]

Annual CO_2	Total Emissions				Change from Baseline		
(million metric tons)	Baseline	Proposal	Existing Source Rule Only	New Source Rule Only	Proposal	Existing Source Rule Only	New Source Rule Only
2028	1,222	1,212	1,209	1,227	-10	-13	4
2030	972	882	871	988	-89	-100	17
2035	608	572	574	606	-37	-34	-3
2040	481	458	457	478	-24	-24	-3
2045	406	387	392	406	-19	-14	0
Cumulative (2028-47)	12,223	11,510	11,512	12,246	-713	-711	23

Annual CO_2	Total Emissions from Existing Sources only				Change from Baseline		
(million metric tons)	Baseline	Proposal	Existing Source Rule Only	New Source Rule Only	Proposal	Existing Source Rule Only	New Source Rule Only
2028	1,163	1,144	1,136	1,174	-19	-28	11
2030	911	810	793	934	-101	-118	23
2035	539	518	488	565	-21	-50	26
2040	413	405	379	434	-8	-33	21
2045	334	329	312	355	-6	-22	20
Cumulative (2028-47)	1,163	1,144	1,136	1,174	-19	-28	11

Annual CO_2	Total Emissions from New Sources only				Change from Baseline		
(million metric tons)	Baseline	Proposal	Existing Source Rule Only	New Source Rule Only	Proposal	Existing Source Rule Only	New Source Rule Only
2028	59	68	73	52	9	14	-7
2030	61	73	79	54	12	18	-7
2035	70	54	85	41	-16	16	-29
2040	68	52	78	45	-16	9	-24
2045	71	58	79	51	-13	8	-20
Cumulative (2028-47)	59	68	73	52	9	14	-7

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

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 proposed requirements. 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 C-5.

Table C-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	Proposal	Existing Source Rule Only	New Source Rule Only	Proposal	Existing Source Rule Only	New Source Rule Only
2028	457	449	447	460	-7	-10	3
2030	368	304	295	371	-64	-73	4
2035	214	193	186	215	-21	-28	1
2040	162	149	145	158	-13	-17	-5
Ozone Season NO_X[a]	**Total Emissions**				**Change from Baseline**		
(Thousand Tons)	Baseline	Proposal	Existing Source Rule Only	New Source Rule Only	Proposal	Existing Source Rule Only	New Source Rule Only
2028	195	191	190	196	-3	-5	1
2030	163	142	136	164	-22	-27	1
2035	104	97	94	105	-7	-10	0
2040	80	76	74	77	-4	-6	-3
Annual SO_2	**Total Emissions**				**Change from Baseline**		
(Thousand Tons)	Baseline	Proposal	Existing Source Rule Only	New Source Rule Only	Proposal	Existing Source Rule Only	New Source Rule Only
2028	394	382	378	399	-12	-16	5
2030	282	175	167	286	-107	-115	4
2035	130	89	88	127	-41	-42	-3
2040	89	59	59	83	-30	-30	-6
Direct $PM_{2.5}$	**Total Emissions**				**Change from Baseline**		
(Tons)	Baseline	Proposal	Existing Source Rule Only	New Source Rule Only	Proposal	Existing Source Rule Only	New Source Rule Only
2028	75	73	73	75	-1	-1	0
2030	66	60	60	65	-6	-6	0
2035	47	45	44	47	-1	-3	1
2040	38	38	36	39	-1	-2	0

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

C.4 Impacts on Fuel Use and Generation Mix

The proposed NSPS and proposed 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 and 2040 IPM model run years under the proposal and under the proposed Emission Guidelines and proposed NSPS independently.

As outlined in Table C-6, under the proposed existing source rule only, coal consumption falls more than under the proposal, while coal consumption falls least under the proposed new source rule only. Under the existing source rule only, GHG mitigation measures apply to existing coal-fired EGUs as outlined in Table C-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 C-2. Hence generation and emissions from these sources falls and are compensated for by increases in generation and emissions from existing sources.

Table C-6 2028, 2030, 2035 and 2040 Projected U.S. Power Sector Coal Use for the Baseline and the Illustrative Scenarios

		Million Tons				Percent Change from Baseline		
	Year	Baseline	Proposal	Existing Source Rule Only	New Source Rule Only	Proposal	Existing Source Rule Only	New Source Rule Only
Appalachia	2028	48	48	46	50	-2%	-6%	4%
Interior	2028	51	49	49	51	-4%	-4%	0%
Waste Coal	2028	4	4	4	4	0%	0%	0%
West	2028	148	145	146	149	-2%	-2%	0%
Total	2028	252	246	245	254	-2%	-3%	1%
Appalachia	2030	28	19	17	30	-31%	-41%	5%
Interior	2030	37	31	31	37	-17%	-17%	1%
Waste Coal	2030	4	3	3	4	-32%	-32%	0%
West	2030	107	52	53	106	-51%	-50%	-1%
Total	2030	176	105	103	177	-40%	-41%	1%
Appalachia	2035	11	10	10	14	-8%	-8%	27%
Interior	2035	20	21	20	20	9%	0%	2%
Waste Coal	2035	2	0	0	2	-83%	-85%	-10%
West	2035	48	30	33	43	-37%	-31%	-10%
Total	2035	80	62	63	79	-23%	-22%	-2%
Appalachia	2040	6	7	5	8	34%	-5%	48%
Interior	2040	16	19	19	16	25%	25%	0%
Waste Coal	2040	2	0	0	2	-100%	-100%	-12%
West	2040	39	26	28	34	-33%	-27%	-13%
Total	2040	62	53	53	59	-15%	-14%	-4%

As outlined in Table C-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 proposal (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 C-7 2028, 2030, 2035 and 2040 Projected Power Sector Natural Gas Use for the Baseline and the Illustrative Scenarios

	Trillion Cubic Feet				Percent Change from Baseline		
Year	Baseline	Proposal	Existing Source Rule Only	New Source Rule Only	Proposal	Existing Source Rule Only	New Source Rule Only
2028	12.5	12.6	12.6	12.5	0%	1%	0%
2030	12.6	13.6	13.7	12.6	8%	8%	0%
2035	9.9	9.9	10.1	9.7	-1%	1%	-2%
2040	8.1	7.9	8.1	7.9	-2%	0%	-3%

As outlined in Table C-8 and Table C-9 coal and gas prices are similar under the Proposal and Existing Source rules, while changes are smaller under the Proposed NSPS.

Table C-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	Proposal	Existing Source Rule Only	New Source Rule Only	Proposal	Existing Source Rule Only	New Source Rule Only
Minemouth	2028	1.16	1.16	1.15	1.16	0%	0%	0%
Delivered		1.59	1.58	1.58	1.60	-1%	-1%	0%
Minemouth	2030	1.17	1.27	1.26	1.17	8%	7%	0%
Delivered		1.47	1.47	1.46	1.48	0%	0%	1%
Minemouth	2035	1.34	1.41	1.40	1.35	5%	4%	1%
Delivered		1.38	1.40	1.40	1.41	2%	1%	2%
Minemouth	2040	1.42	1.49	1.48	1.44	5%	4%	1%
Delivered		1.42	1.45	1.45	1.46	2%	2%	3%

Table C-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	Proposal	Existing Source Rule Only	New Source Rule Only	Proposal	Existing Source Rule Only	New Source Rule Only
Henry Hub	2028	3.0	3.0	3.0	3.0	0%	0%	0%
Delivered		3.0	3.0	3.0	3.0	0%	0%	0%
Henry Hub	2030	2.4	2.6	2.6	2.4	10%	10%	0%
Delivered		2.5	2.8	2.8	2.5	9%	9%	0%
Henry Hub	2035	1.9	1.8	1.9	1.8	-2%	0%	-2%
Delivered		2.1	2.0	2.1	2.0	-2%	1%	-3%
Henry Hub	2040	2.0	2.0	2.1	2.0	-2%	1%	-3%
Delivered		2.2	2.1	2.2	2.1	-3%	1%	-3%

As outlined in Table C-10 the generation mix remains generally similar under the proposal 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 proposal. 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 C-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	Proposal	Existing Source Rule Only	New Source Rule Only	Proposal	Existing Source Rule Only	New Source Rule Only
Coal	2028	484	472	468	489	-2%	-3%	1%
Natural Gas		1,773	1,783	1,789	1,766	1%	1%	0%
Nuclear		765	765	765	765	0%	0%	0%
Hydro		294	294	295	293	0%	0%	0%
Non-Hydro RE		964	966	966	964	0%	0%	0%
Oil/Gas Steam		30	30	29	31	0%	-2%	3%
Other		30	30	30	30	0%	0%	0%
Grand Total		4,341	4,341	4,342	4,339	0%	0%	0%
Coal	2030	309	170	166	315	-45%	-46%	2%
Natural Gas		1,771	1,879	1,889	1,765	6%	7%	0%
Nuclear		734	734	734	734	0%	0%	0%
Hydro		303	303	303	302	0%	0%	0%
Non-Hydro RE		1,269	1,278	1,276	1,266	1%	1%	0%
Oil/Gas Steam		33	50	45	34	52%	38%	6%
Other		29	29	29	29	0%	0%	0%
Grand Total		4,447	4,442	4,443	4,446	0%	0%	0%
Coal	2035	120	87	86	122	-28%	-28%	2%
Natural Gas		1,402	1,419	1,429	1,390	1%	2%	-1%
Nuclear		660	660	660	661	0%	0%	0%
Hydro		329	328	328	328	0%	0%	0%
Non-Hydro RE		2,180	2,186	2,188	2,179	0%	0%	0%
Oil/Gas Steam		16	18	15	21	13%	-9%	27%
Other		29	29	29	29	0%	0%	0%
Grand Total		4,736	4,728	4,736	4,729	0%	0%	0%
Coal	2040	79	65	64	78	-17%	-18%	0%
Natural Gas		1,164	1,173	1,169	1,163	1%	0%	0%
Nuclear		616	616	616	616	0%	0%	0%
Hydro		346	346	346	345	0%	0%	0%
Non-Hydro RE		2,826	2,818	2,839	2,814	0%	0%	0%
Oil/Gas Steam		3	3	3	3	-3%	-23%	0%
Other		28	28	27	28	0%	0%	0%
Grand Total		5,061	5,050	5,063	5,048	0%	0%	0%

As outlined in Table C-11 the capacity mix follows similar trends to those seen under the generation mix table. The capacity mix under the proposal 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 proposal results.

Table C-11 2028, 2030, 2035 and 2040 Projected U.S. Capacity by Fuel Type for the Baseline and the Illustrative Scenarios

		Capacity (GW)				Percent Change from Baseline		
	Year	**Baseline**	**Proposal**	**Existing Source Rule Only**	**New Source Rule Only**	**Proposal**	**Existing Source Rule Only**	**New Source Rule Only**
Coal	2028	100	99	100	101	-2%	-1%	0%
Natural Gas		463	467	468	461	1%	1%	0%
Nuclear		96	96	96	96	0%	0%	0%
Hydro		102	102	102	102	0%	0%	0%
Non-Hydro RE		315	316	315	315	0%	0%	0%
Oil/Gas Steam		63	63	63	63	0%	0%	0%
Other		7	7	7	7	0%	0%	0%
Grand Total		1,146	1,149	1,151	1,144	0%	0%	0%
Coal	2030	69	59	56	70	-15%	-18%	1%
Natural Gas		461	465	467	459	1%	1%	0%
Nuclear		92	92	92	92	0%	0%	0%
Hydro		104	104	104	104	0%	0%	0%
Non-Hydro RE		403	405	404	403	0%	0%	0%
Oil/Gas Steam		60	69	69	62	15%	14%	2%
Other		7	7	7	7	0%	0%	0%
Grand Total		1,196	1,200	1,199	1,196	0%	0%	0%
Coal	2035	44	13	13	46	-70%	-70%	4%
Natural Gas		470	494	490	472	5%	4%	1%
Nuclear		84	84	84	84	0%	0%	0%
Hydro		108	108	108	108	0%	0%	0%
Non-Hydro RE		668	670	669	669	0%	0%	0%
Oil/Gas Steam		59	67	67	59	13%	14%	-1%
Other		7	7	7	7	0%	0%	0%
Grand Total		1,439	1,443	1,438	1,444	0%	0%	0%
Coal	2040	35	10	9	36	-73%	-73%	2%
Natural Gas		513	533	530	515	4%	3%	0%
Nuclear		79	79	79	79	0%	0%	0%
Hydro		110	110	110	110	0%	0%	0%
Non-Hydro RE		868	867	872	866	0%	0%	0%
Oil/Gas Steam		59	67	67	58	14%	14%	-1%
Other		7	7	7	7	0%	0%	0%
Grand Total		1,672	1,672	1,675	1,672	0%	0%	0%

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