Regulatory Impact Analysis for the Final Partial Repeal of the Carbon Pollution Standards for Fossil Fuel-Fired Electric Generating Units

EPA-452/R-26-003
September 2026

Regulatory Impact Analysis for the Final Partial Repeal of the Carbon Pollution Standards for Fossil Fuel-Fired Electric Generating Units

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1 EXECUTIVE SUMMARY

1.1 Introduction

In this final rule, the U.S. Environmental Protection Agency (EPA) is repealing most provisions of the 2024 Carbon Pollution Standards for greenhouse gas emissions from fossil fuel-fired electric generating units based on a reevaluation of the best system of emission reduction (BSER) for the relevant subcategories. Specifically, the EPA is repealing the emission guidelines for existing fossil fuel-fired steam generating units, the carbon capture and sequestration/storage (CCS)-based standards for coal-fired steam generating units undertaking a large modification, and the CCS-based standards for new base load stationary combustion turbines (*i.e.*, Phase 2 standards).[1]

In accordance with Executive Orders (E.O). 12866 and 13563, the guidelines of OMB Circular A-4, and *EPA's Guidelines for Preparing Economic Analyses* (U.S. EPA, 2024), this Regulatory Impact Analysis (RIA) analyzes the regulatory compliance costs and benefits associated with this final repeal. This RIA builds upon the analysis in the preceding RIA for the proposed repeal as well as feedback provided through public comments.

The "baseline" is a business-as-usual scenario that ordinarily represents the behavior of the regulated sector under market and regulatory conditions in the absence of a regulatory action. From the perspective of this action, the 2024 Carbon Pollution Standards (CPS) are in the baseline. Therefore, the scenario in this RIA representing the baseline includes an illustrative characterization of the 2024 CPS. This scenario is referred to as the "baseline" and "baseline (with CPS)" throughout this RIA. Compared to this baseline scenario is the "final repeal" scenario that represents this final rule repealing the 2024 CPS.

In this RIA, we evaluate the potential impacts of the action using the present value (PV) and equivalent annual value (EAV) of cost estimates, calculated for the years 2026 to 2047, discounted to 2025 using 3 and 7 percent discount rates. In addition, in Section 3 the Agency

[1] As stated in the preamble, the EPA concludes that previous projects that failed to achieve 90 percent CCS are not a sufficient basis to determine that the technology has been adequately demonstrated. Additionally, the CO_2 capture, pipeline, and sequestration infrastructure necessary to implement 90 percent CCS does not currently exist and would need to be broadly deployed. Because it is significantly unlikely that the necessary infrastructure for CCS can be deployed by the January 1, 2032, compliance date, the EPA is finalizing the determination that the degree of emission limitation and standards of performance in the CPS are not achievable.

presents the assessment for specific snapshot years, consistent with historical practice. These snapshot years are 2030, 2035, 2040 and 2045.[2] We present information about potential impacts of this final action on electricity markets and markets outside the electricity sector. The RIA also presents a discussion of uncertainties and limitations of the analysis. While the results are described and presented in more detail throughout the RIA, we present the high-level results of the analysis below.

1.2 Cost Savings

This RIA estimates that the partial repeal of the CPS will avoid substantial compliance and societal costs. This section presents three sets of estimates of these avoided costs. We first report estimates of avoided costs paid by the power sector. Second, we present estimates of the reduced real resource costs paid by society as a result of this final repeal. Third, to estimate the avoided social costs across the entire economy, the EPA used its computable general equilibrium model, SAGE.

Table 1-1 presents the projected compliance cost savings from the perspective of the power sector under the final repeal with adjustments to account for updated estimates of monitoring, reporting, and recordkeeping (MR&R) costs.[3] The compliance cost savings from the power sector in Table 1-1 are the difference in projected expenditures on capital, operations and maintenance, fuel, transmission, CO_2 storage and transportation costs, and net tax payments due to this final repeal.[4] These estimates are based on Integrated Planning Model (IPM) projections supplemented with cost estimates for MR&R.[5]

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[2] Consistent with past practice using the Integrated Planning Model (IPM) for power sector modeling, this analysis uses a near term first year and then relies on five-year increments for the remainder of the forecast period.

[3] Compliance costs refer to the difference between policy and baseline IPM projected capital, operations and maintenance, fuel, transmission, CO_2 storage and transportation costs, and net tax payments. Other costs are not accounted for. Please see Sections 3.4 and 5.2 for further discussion of the differences between compliance costs and social costs.

[4] Net tax payments reflect the difference between taxes collected and subsidies disbursed. We project a difference in new construction and retirements between the baseline (with CPS) and final repeal scenarios, which has implications for net taxes.

[5] Information on IPM can be found at the following link: https://www.epa.gov/power-sector-modeling/2025-reference-case. The most recent complete documentation, for the IPM 2023 Reference Case, can be found here: https://www.epa.gov/system/files/documents/2025-02/epa-2023-reference-case.pdf. As discussed in Section 3.3.2, the analysis in this document uses an Updated 2025 Reference Case. Documentation for the 2025 Reference incremental to the complete 2023 Reference Case documentation can be found here: https://www.epa.gov/system/files/documents/2025-12/epa-2025-reference-case-incremental-documentation.pdf.

Table 1-1 Present Value and Equivalent Annualized Value Estimates of Compliance Cost Savings from 2026-2047 (billion 2024 dollars, discounted to 2025)

3% Discount Rate		7% Discount Rate	
PV	EAV	PV	EAV
160	10	95	8.6

Note: Values have been rounded to two significant figures.

The compliance cost savings reported in Table 1-1 are not real resource costs. The change in real resource costs includes expenditures on capital, labor, fuel, and other inputs used by the power industry and excludes transfers, such as tax payments and tax credits (OMB 2003, U.S. EPA 2024). In contrast to the compliance cost savings in Table 1-1, the real resource costs account for the full costs that would have been paid by society for the inputs used for compliance. This is important for this final rule in that the power sector would otherwise acquire tax credits for the capture of CO_2 for sequestration, as well as tax credits for certain types of generators and energy storage, as an outcome of the 2024 CPS. The claiming of these tax credits would have reduced costs from the perspective of firms in the power sector but would have led to the use of resources that are a cost from a societal perspective. These societal costs will be avoided because of this final action. Section 3.4.3 presents these real resource cost savings which are estimated using IPM results. The PV and EAV of real resource cost savings from 2026 to 2047 are respectively $280 billion and $18 billion at a three percent discount rate, and $180 billion and $16 billion at a seven percent discount rate. These PVs and EAVs are in 2024 dollars discounted to 2025.

The compliance costs savings reported in Table 1-1 are also not social costs, as the estimates do not account for changes in economic welfare outside the electricity sector. This final action will affect production in industries that use electricity, as changes in the price of electricity can affect its use in the production of other goods and services. This final action will also affect industries that supply inputs to the sector (e.g., energy commodities). Furthermore, household consumption patterns will change as a result of electricity, natural gas, and other final good price changes. Changes in firm and household behavior could also interact with pre-existing market distortions, such as taxes.

To evaluate these broad economy-wide impacts of a regulatory action and its social cost, a computable general equilibrium (CGE) model can be used. The EPA used the peer-reviewed CGE model SAGE to evaluate the economy-wide social costs and economic impacts of the action (U.S. EPA Science Advisory Board, 2020; Marten et al., 2024). The annualized reduction in social cost estimated in SAGE for the action is approximately $23 billion (2024 dollars) between 2026 and 2047. Note that SAGE does not account for the effects of changing environmental quality as a result of this final action. Section 5.2 of the RIA provides additional explanation of how the social cost was estimated using SAGE, as well as the potential household distributional impacts. Both Sections 3.4 and 5.2 provide further discussion of the differences between compliance costs and social costs.

1.3 Emissions Changes of the Regulated Pollutant

The quantified emission estimates presented in the RIA include changes in CO_2 emissions, which is the regulated pollutant under CPS. We also estimate emissions changes for non-regulated pollutants which may result from changes in dispatch as the relative operating costs for affected units are projected to change under the final repeal. These changes are relative to a baseline with the CPS requirements in place for each modeled year. Table 1-2 presents the CO_2 emission changes associated with the action, which are projected to increase relative to the baseline (with CPS).

Table 1-2 Carbon Dioxide Emissions Changes [a]

	CO_2 (million metric tons)
2030	20
2035	406
2040	533
2045	486

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

1.4 Economic Impacts

As a result of the change in compliance costs incurred by the regulated sector, the action has economic and energy market implications. Table 1-3 presents a variety of energy market impact estimates for 2030, 2035, 2040, and 2045 for the action. However, there are several key areas of uncertainty inherent in these projections as outlined in Section 3.5.

Table 1-3 Summary of Certain Energy Market Impacts

	2030	2035	2040	2045
Retail electricity prices	0.7%	-5.8%	-1.1%	-2.6%
Average price of coal delivered to the power sector	4.3%	10.5%	10.0%	27.3%
Coal production for power sector use (tons)	4%	47%	57%	1405%
Price of natural gas delivered to power sector	-2.2%	-8.5%	0.6%	-1.9%
Price of average Henry Hub (spot)	-2.2%	-8.2%	0.7%	-1.9%
Natural gas use for electricity generation	-1.6%	-8.9%	1.9%	-3.1%

Note: See Table 3-18 for further details on the scenario projections used to develop these estimates.

A more detailed version of this table is found in Section 3.4.4 of this RIA. Section 3.4.4 also contains additional discussion of energy market impacts as well as the underlying analytic methods.

1.5 Net Benefits Associated with the Regulated Pollutant from the Final Repeal

The quantified net benefits associated with the regulated pollutants are the cost savings of this action as presented above in Table 1-1. Consistent with E.O. 14154 "Unleashing American Energy" (90 FR 8353, January 20, 2025) and the memorandum titled "Guidance Implementing Section 6 of Executive Order 14154, Entitled 'Unleashing American Energy'", the EPA did not monetize impacts associated with CO_2 emissions changes in Table 1-2.[6] The rest of the RIA presents a full discussion of the projected costs and benefits of this final action, as well as a discussion of uncertainty and additional impacts that the EPA could not quantify or monetize.

[6] The memorandum titled "Guidance Implementing Section 6 of Executive Order 14154, Entitled 'Unleashing American Energy'" is found here: https://www.whitehouse.gov/wp-content/uploads/2025/02/M-25-27-Guidance-Implementing-Section-6-of-Executive-Order-14154-Entitled-Unleashing-American-Energy.pdf

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2 INTRODUCTION AND BACKGROUND

2.1 Introduction

In this final rule, the U.S. Environmental Protection Agency (EPA) is repealing most provisions of the 2024 Carbon Pollution Standards for greenhouse gas emissions from fossil fuel-fired electric generating units based on a reevaluation of the best system of emission reduction (BSER) for the relevant subcategories. Specifically, the EPA is repealing the emission guidelines for existing fossil fuel-fired steam generating units, the carbon capture and sequestration/storage (CCS)-based standards for coal-fired steam generating units undertaking a large modification, and the CCS-based standards for new base load stationary combustion turbines (*i.e.*, Phase 2 standards).[7]

2.2 Purpose of RIA

In accordance with Executive Orders (E.O). 12866 and 13563, the guidelines of OMB Circular A-4, and *EPA's Guidelines for Preparing Economic Analyses* (U.S. EPA, 2024), the EPA prepared this RIA for this "significant regulatory action." This action is an economically significant regulatory action because it may have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or state, local, or tribal governments or communities. This RIA addresses the regulatory compliance costs, emission impacts, and benefits of this final action. Additionally, this RIA includes information about potential impacts of the final action on electricity markets and markets outside the electricity sector.

[7] As stated in the preamble, the EPA concludes that previous projects that failed to achieve 90 percent CCS are not a sufficient basis to determine that the technology has been adequately demonstrated. Additionally, the CO_2 capture, pipeline, and sequestration infrastructure necessary to implement 90 percent CCS does not currently exist and would need to be broadly deployed. Because it is significantly unlikely that the necessary infrastructure for CCS can be deployed by the January 1, 2032, compliance date, the EPA is finalizing the determination that the degree of emission limitation and standards of performance in the CPS are not achievable.

2.3 Overview of the RIA

2.3.1 Years of Analysis in this RIA

In this RIA, we evaluate the potential impacts of this final action using the present value (PV) of cost estimates, calculated for the years 2026 to 2047, discounted to 2025. We estimate that 2026 is the first and only year that there would be avoided monitoring, reporting, and recordkeeping (MR&R) costs under this action, which is why the timeframe of this RIA begins in 2026. There are no estimated impacts in 2027. In addition, in Section 3 the Agency presents the assessment for the specific snapshot years of 2030, 2035, 2040 and 2045.

2.3.2 Baseline (with CPS)

The "baseline" is a business-as-usual scenario that, in the context of this analysis, represents expected behavior in the power industry sector under market and regulatory conditions in the absence of a regulatory action. As described in that section, the baseline includes the 2024 CPS. Details about the CPS requirements modeled in the baseline are provided in Section 3.2. In order to maintain consistency with the final CPS analysis as well as the proposed repeal, this analysis relies on the Integrated Planning Model (IPM), a least-cost optimization model dynamic linear programming model that can be used to project power sector behavior under future business-as-usual conditions and to examine prospective air pollution control policies throughout the contiguous United States for the entire electric power system. The baseline characterization in the IPM modeling as well as additional information around model inputs and history are detailed in Section 3.3.2. The IPM baseline also includes power-sector related provisions from the One Big Beautiful Bill Act (OBBBA) of 2025.

2.3.3 Final Repeal Scenario

To estimate the costs, benefits, and economic and energy market impacts of the CPS repeal, the EPA conducted quantitative analysis comparing a baseline that includes the CPS requirements with a final repeal scenario that does not include the CPS requirements to illustrate the potential impacts of repealing the CPS. For additional information on the analysis of the final repeal, see section 3.3.3.

2.4 References

OMB. (2003). *Circular A-4: Regulatory Analysis*. Washington DC. https://www.whitehouse.gov/wp-content/uploads/2025/08/CircularA-4.pdf

U.S. EPA. (2024). *Guidelines for Preparing Economic Analyses (3rd edition)*. EPA-240-R-24-001. Washington, DC. https://www.epa.gov/system/files/documents/2024-12/guidelines-for-preparing-economic-analyses_final_508-compliant_compressed.pdf

3 COMPLIANCE COSTS, EMISSIONS, AND ENERGY IMPACTS

3.1 Introduction

This section reports the compliance costs, emissions, and energy analyses performed for the final partial repeal of the Carbon Pollution Standards. In order to maintain consistency with the final CPS analysis as well as the proposed repeal, the EPA used the Integrated Planning Model (IPM) to conduct the electric generating units (EGU) analysis discussed in this section.[8] For purposes of this analysis, the EPA relied on an updated version of IPM (IPM Baseline v7.24), which captured key changes to the energy sector that have occurred since publication of the analysis supporting the Final CPS regulations. These include significantly higher electricity demand driven primarily by data center use in applications supporting artificial intelligence, and the passage of the One Big Beautiful Bill Act (OBBA).[9] In turn these updates result in higher levels of coal fired generation and economic additions of natural gas turbines absent the CPS requirements as compared to the earlier analysis. As a result, the updated analysis presented here projects higher avoided compliance costs and greater forgone emissions reductions as a result of the repeal of the CPS as compared to the prior analysis.

3.2 CPS Requirements Modeled in the Baseline Scenario

The CPS established regulations to reduce GHG emissions from certain fossil fuel-fired electric generating units. The EGUs covered by these rules were existing fossil fuel-fired steam generating units greater than 25 MW, and new and reconstructed fossil fuel-fired combustion turbines that commenced construction or reconstruction after the publication of the proposed CPS regulation (*i.e.*, May 23, 2023). This RIA evaluates the benefits, costs, and certain impacts of repealing the CPS; specifically, repealing measures listed in Table 3-1 and Table 3-2. It should be noted that while this action would not repeal Phase 1 of the New Source Performance Standards for new combustion turbines, the modeling assumes repeal of all requirements under the CPS. For the reasons listed below, the EPA believes that the inclusion of these requirements would not change the conclusion reached in this RIA. The EPA notes that the efficiency

[8] Information on IPM can be found at the following link: https://www.epa.gov/airmarkets/power-sector-modeling.
[9] The One Big Beautiful Bill Act (Pub. L. No. 119-21) includes revisions to tax credit provisions laid our under the earlier Inflation Reduction Act (IRA), which affect power sector operations. Details of these changes are incorporated into the IPM modeling. Details are included in the IPM documentation. Documentation available at: https://www.epa.gov/power-sector-modeling

assumptions for new natural gas combined cycle (NGCC) builds, which are taken from the EIA's Annual Energy Outlook 2025,[10] would allow for modeled new combined cycle units to comply with efficiency standards laid out in the CPS without any further modification (i.e. the Phase 1 standards for combined cycles operating at baseload would be non-binding as modeled). Natural gas combustion turbines (NGCTs) operating at baseload capacity (i.e. units that have annual average capacity factors in excess of 40 percent) would not be compliant with the Phase 1 requirements. In 2030, of the projected 42 GW of new combustion turbine capacity, about 440 MW (about 1 percent) are projected to operate at baseload levels, while in 2035 of the projected 42 GW of new combustion turbine capacity, about 1 GW (approximately 3 percent of total NGCT builds) are projected to operate at baseload levels. New combustion turbines are not projected to operate at baseload levels thereafter. In 2035, the 1 GW of new combustion turbine units identified above are collectively projected to operate at a 49 percent capacity factor – in other words if we were to re-run the model with the Phase 1 standards maintained, we would expect a roughly 0.4 GW higher build out of combustion turbines (or a 1 percent increase in projected NGCT capacity) to sustain the level of generation while not exceeding the baseload generation level. This change would not be sufficient to change the conclusions presented here, since they would not affect the overall level of emissions and would result in a change in estimated undiscounted annual costs by up to about $36 million (i.e., serve to lower projected compliance costs by less than 0.5 percent).

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

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

[a] All years shown in this table reflect IPM run years. Note that IPM run years encompass the specific calendar year requirements of BSER.
[b] Coal units that lack existing SCR controls must install these controls in addition to CCS to comply.
[c] Coal-fired EGUs that convert entirely to burn natural gas by 2030 are no longer subject to coal-fired EGU mitigation measures outlined above.

[10] Please see table 3 of the "Assumptions to the Annual Energy Outlook 2025: Electricity Market Module", available at: https://www.eia.gov/outlooks/aeo/assumptions/pdf/EMM_Assumptions.pdf

[d] To evaluate the differences in the impacts of a scenario with and without the CPS standards, the EPA modeled a scenario where 90 percent CCS was allowed in the modeling solution set, achieved the design capture efficiency, and there were not limitations affecting the deployment of CCS by the compliance date. As detailed in the preamble, the EPA believes that there are limitations to achieving 90 percent CCS in practice. For the reasons detailed in section IV of the preamble, the EPA has determined that 90 percent CCS has not been adequately demonstrated and the deployment of CCS by the January 1, 2032, compliance date is unlikely to be achieved.

Table 3-2 Summary of GHG Mitigation Measures for New Sources by Source Category under the Illustrative CPS Rules[a,b,c,d]

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

[a] All years shown in this table reflect IPM run years. Note that IPM run years encompass the specific calendar year requirements of BSER.
[b] Delivered hydrogen price is assumed to be $2/kg in all years.
[c] The modeling does not reflect the requirements of the variable subcategory. We estimate this would have a limited impact on the results.
[d] To evaluate the differences in the impacts of a scenario with and without the CPS standards, the EPA modeled a scenario where 90 percent CCS was available, achieved the design capture efficiency, and there were not limitations affecting the deployment of CCS by the compliance date. As detailed in the preamble, the EPA believes that these assumptions may not be realized in practice. The EPA has determined that 90 percent CSS has not been adequately demonstrated and the deployment of CCS by the January 1, 2032, compliance date is unlikely to be achieved.

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.[11] This

[11] 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 and 2029, calendar years 2030-31 to run year 2030, calendar years 2032-37 to run year 2035, calendar years 2038-41 to

RIA compares a baseline scenario that includes the CPS with a scenario that does not include these rules to illustrate the potential impacts of repealing the CPS.

The baseline scenario (i.e., the scenario that includes CPS measures) includes a baseload definition of 40 percent annual capacity factor for new turbine additions. The baseline scenario assumes all existing coal-fired steam generating units in the medium-term subcategory must co-fire at least 40 percent natural gas by the 2030 run year consistent with the requirements under the CPS regulations, while all long-term existing coal-fired steam generating units must install CCS by the 2035 run year.[12]

The GHG mitigation measures in this RIA are illustrative since sources are not required to install any particular controls to comply with standards of performance under CAA section 111 and because States implement the emission guidelines for existing sources under CAA section 111(d), as discussed in section II.C of the final rule preamble. Thus, the impacts of the CPS could have been different to the extent sources or States would have made different choices than those assumed in the illustrative baseline scenario presented in this RIA. Additionally, the way that EGUs might have complied with the GHG mitigation measures could have differed from the methods forecasted in the modeling for this RIA. Further, the EPA's modeling provides important information about the way the power sector could have reacted to these requirements if 90 percent CCS could be deployed consistent with the requirements of the CPS. However, as explained in section IV of the final rule preamble, the EPA has determined that 90 percent CO_2 capture and, therefore, 90 percent CCS have not been adequately demonstrated and that the degree of emission limitation is unachievable because it is unlikely that the infrastructure for CCS (including capture equipment, transport, and sequestration) can be deployed by the January 1, 2032, compliance date. For the reasons discussed in section IV of the final rule preamble, the EPA did not perform a technical evaluation of whether lower levels of CO_2 capture efficiency have been adequately demonstrated or evaluate later compliance dates that would impact the achievability of the degree of emission limitation. As discussed later in Section 3.5, the EPA has

run year 2040, calendar years 2042-47 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

[12] 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

also modeled a scenario in which 90 percent CCS is not allowed to be built in the solution set. See Sections 3.3 and 3.4 for further discussion of the modeling approach used in the analysis presented below.

3.3 Power Sector Modeling Framework

Projections about future performance, particularly of a sector as large and dynamic as the power sector are inherently uncertain. In order to maintain consistency with the final CPS analysis and proposed repeal of the CPS, the EPA relied on the same IPM modeling framework to perform the analysis presented here. However, there remain significant uncertainties and limitations in the analysis driven by assumptions embedded in the modeling. These include the future demand for electricity and the pattern of that demand, the ability of new resources to be added at the levels projected by the study, the cost and performance of new technology, particularly technology such as CCS which has not yet been broadly deployed in the US power sector. Input fuel prices and the shape of the fuel supply curve can meaningfully affect the modeled solution, while the ability of the grid to manage a shift in the generation resource mix and capacity turnover to the extent projected by a given model can affect the real-world feasibility of such a solution. These limitations and uncertainties are outlined in more detail in Section 3.5.

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

IPM, developed by the consultancy ICF, is a multi-regional, dynamic, deterministic linear programming model of the contiguous U.S. electric power sector. It provides estimates of least cost capacity expansion, electricity dispatch, and emissions control strategies while meeting energy demand and environmental, transmission, dispatch, and reliability constraints. The model represents electricity markets through a 67-region representation that is based on the NERC Long-Term Reliability Assessment and includes transmission capabilities and constraints between the regions. This ensures that key transmission constraints are represented in IPM and that each individual IPM region has less internal transmission congestion based on today's loads and resource mix.

The EPA has used IPM for almost three decades to better understand power sector behavior under future business-as-usual (i.e. how electricity is likely to be produced absent particular policy interventions) conditions and to evaluate the economic and emissions impacts of prospective environmental policies. The model is designed to reflect electricity markets as accurately as possible. The EPA uses the best available information from utilities, industry experts, gas and coal market experts, financial institutions, and government statistics as the basis for the detailed power sector modeling in IPM. The model documentation provides additional information on the assumptions discussed here as well as all other model assumptions and inputs that went into the development of this analysis.[13]

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.[14] GMM is designed to perform comprehensive assessments of the entire North American gas flow pattern. It is a large-scale, dynamic linear program that models economic decision-making to minimize the overall cost of meeting natural gas demand. GMM is reliable and efficient in analyzing the broad range of natural gas market issues. It is important to note that as outlined in Section 3.5, assumptions such as those around well productivity, development cost, pipeline infrastructure, and export demand have impacts on the gas supply curve and transportation adders that are implemented within IPM and can therefore affect the cost-minimizing resource mix chosen by the power sector model.

[13] 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/system/files/documents/2025-02/epa-2023-reference-case.pdf. Incremental updates for the EPA 2025 Reference Case are documented here: https://www.epa.gov/system/files/documents/2025-12/epa-2025-reference-case-incremental-documentation.pdf

[14] See Chapter 8 of EPA's Baseline run using IPM v6 documentation, available at: https://www.epa.gov/system/files/documents/2025-02/epa-2023-reference-case.pdf

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.[15] While the model includes details on supply and transportation of coal it is important to note that as with any model this is a necessary simplification of the number of possible pathways of production and transporting coal for use within the US power sector.

To estimate the annualized costs of additional capital investments in the power sector, The EPA uses a conventional and widely accepted approach that applies a capital recovery factor (CRF) multiplier to capital investments and adds that to the annual incremental operating expenses. The CRF is derived from estimates of the power sector's cost of capital (i.e., private discount rate), the amount of insurance coverage required, local property taxes, and the life of capital.[16] 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, reflecting of the varying investment horizons, interest rates and financing structures available to different owners and operators of EGUs.[17]

The EPA has used IPM extensively over the past three decades to analyze options for reducing power sector emissions. Previously, the model has been used to estimate the costs, emission changes, and power sector impacts for the Clean Air Interstate Rule (U.S. EPA, 2005), the Cross-State Air Pollution Rule (U.S. EPA, 2011a), the Mercury and Air Toxics Standards (U.S. EPA, 2011b), the Clean Power Plan for Existing Power Plants (U.S. EPA, 2015b), the

[15] See Chapter 7 of the IPM documentation, available at: https://www.epa.gov/system/files/documents/2025-02/epa-2023-reference-case.pdf
[16] See Chapter 10 of the IPM documentation, available at: https://www.epa.gov/system/files/documents/2025-02/epa-2023-reference-case.pdf
[17] Costs modeled in IPM reflect the costs faced by industry, and therefore are net of subsidies included in the IRA

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), the Federal Good Neighbor Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standards (U.S. EPA, 2023), the MATS RTR (U.S. EPA 2024a) and the Carbon Pollution Standards (U.S. EPA, 2024b). The 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), the Steam Electric Reconsideration Rule (U.S. EPA, 2020), and the Effluent Limitation Guidelines (U.S. EPA, 2024d).

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 September 2019 U.S. EPA commissioned a peer review of EPA Baseline version 6, and in October 2014 U.S. EPA commissioned a peer review of EPA Baseline version 5.13 using the IPM. [18] Additionally, and in the late 1990s, the Science Advisory Board reviewed IPM as part of the CAA Amendments Section 812 prospective studies.[19] 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.

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

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

It is important to note that any projection of future behavior entails uncertainties and limitations, including those stemming from key input assumptions such as demand, fuel supply curves and transportation costs, the ability to deploy new technology and the ability manage fleet turnover. A discussion of these limitations and uncertainties is provided in Section 3.5.

3.3.1 EPA's Power Sector Modeling of the Baseline Run and Final Repeal Scenario

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 particular regulatory action. As such, an IPM baseline represents an element of the baseline for this RIA.[20] The EPA frequently updates the IPM baseline to reflect the latest available electricity demand forecasts from the 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 OBBBA.

3.3.2 EPA's IPM Baseline v7.24

For our analysis of the repeal of the CPS, the EPA used EPA's IPM v7.24 Baseline, as well as a companion updated database of EGU units (the National Electricity Energy Data System or NEEDS 07-02-2025) that the EPA generally uses in its modeling applications of IPM.[21] The IPM Baseline includes the 2011 CSAPR, the 2016 CSAPR Update, the 2021 Revised CSAPR Update, as well as the 2020 Mercury and Air Toxics Standards. The IPM baseline also includes the 2015 Effluent Limitation Guidelines (ELG) and the 2015 Coal Combustion Residuals (CCR), and the finalized 2020 ELG and CCR rules.[22] The baseline also includes the 2024 ELG rule and the repeal of the 2024 MATS rule. Additionally, the model was also updated to account for recent updates to state and federal legislation affecting the power sector, including

[20] 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).

[21] Documentation for the updated 2025 Reference Case incremental to the previous 2023 Reference Case is available here: https://www.epa.gov/system/files/documents/2025-12/epa-2025-reference-case-incremental-documentation.pdf. Complete documentation for the 2023 Reference Case is here: https://www.epa.gov/system/files/documents/2025-02/epa-2023-reference-case.pdf

[22] For a full list of modeled policy parameters, please see: https://www.epa.gov/power-sector-modeling/2023-reference-case and https://www.epa.gov/power-sector-modeling/2025-reference-case.

OBBBA (Pub. L. No. 119-21 (July 4, 2025)). The 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 also provides details on the provisions of the OBBBA that were incorporated into this analysis, including provisions relating to tax subsidies for non-emitting generation, energy storage, and CCS.[23] In addition, the model was also updated to account for large projected increases in electricity demand stemming from data centers and Artificial Intelligence (AI) applications, as well as reductions in electricity demand due to the repeal of the 2024 EPA Vehicle Rules. Details of the methodology used to update the energy demand, as well as OBBBA tax changes, are available in the IPM documentation. Additionally, to account for recent changes in retirement announcements by EGU owners and operators, the EPA has reverted to reflecting firm retirements in the model based on EIA-860 data and no longer supplementing these with other announcements of retirements by owners and operators. 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 no longer requiring the GHG mitigation measures presented in Table 3-1, Table 3-2, and Table 3-3. As outlined in Section 3.3 and Section 3.5, there are significant uncertainties embedded in projections of future behavior, and the projections are sensitive to input assumptions around a range of factors including fuel price, demand, and the ability to add new capacity to the electric grid.

3.3.3 Methodology for Evaluating this Rulemaking

To estimate the costs, benefits, and economic and energy market impacts of the CPS repeal, the EPA conducted quantitative analysis comparing a baseline scenario that includes the CPS requirements to a final repeal scenario that does not include the CPS requirements. Details about the CPS requirements analyzed in this RIA are provided above in Section 3.2.

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.

[23] For a discussion of the uncertainties around the modeling of the impacts of the OBBBA including CCS and market conditions, please see the Limitations Discussion in Section 3.5.

While CCS at new and existing sources and co-firing natural gas at existing coal facilities[24] are captured endogenously within IPM v7.24 (the updated platform used to perform this analysis), hydrogen co-firing at new gas EGUs is at present represented exogenously as a fuel that is available at affected sources at a delivered cost of $2/kg, inclusive of subsidies for hydrogen production under section 45V of the US tax code.[25] This cost fully captures the cost of production, transportation and storage of hydrogen for power sector consumption. We also note the model does not track upstream emissions associated with the production of hydrogen (or any other modeled fuels such as coal and natural gas), nor any incremental electricity demand associated with its production, although the costs incorporate the cost of production of the fuel. As outlined in Section 3.4.4 within both the baseline and policy scenarios (*i.e.*, with and without the CPS, respectively) we see minimal consumption of hydrogen for electricity generation given the cost of hydrogen relative to the cost of natural gas – as such the exogenous treatment of hydrogen within the modeling does not meaningfully affect the results.

While hydrogen is modeled as an exogenous input to the model, the cost of fuels such as coal and natural gas that are more widely consumed within the electric sector are modeled endogenously through fuel supply curves and associated transportation costs that simulate the cost of production at various basins and wells, as well as the cost of transportation by different modes from source to sink.

As noted in Section 3.2, IPM estimates compliance costs incurred by regulated firms, but IPM also accounts for changes in subsidy payments and tax payments. Therefore, this RIA presents three sets of costs estimates. First, this RIA presents the IPM estimates of the costs of the final rules to the electricity sector and related energy sectors (i.e., natural gas, coal mining). Second, this RIA presents the IPM estimates as the real resource costs paid by society. Third, to estimate the social costs for the economy as a whole, the EPA has used information from IPM as

[24] For details on CCS modeling in IPM, please see Chapter 6 of the documentation, available at: https://www.epa.gov/system/files/documents/2025-02/epa-2023-reference-case.pdf. Additionally, the EPA has summarized the CCS costs for affected existing coal-fired steam generating units in the memorandum entitled *Updated Evaluation of Best System of Emission Reduction Costs of Carbon Capture and Sequestration/Storage at Existing Coal-Fired Electric Generating Units* in the docket for this rulemaking.

[25] Unlike other fuels in the EPA's model, which are modeled endogenously, the EPA models hydrogen as a fuel with a fixed price regardless of the level of hydrogen demand. The model does not account for any additional electricity/gas demand necessary to produce the hydrogen use projected by the model.

an input into the Agency's computable general equilibrium model, SAGE.[26] The economy-wide analysis is considered a complement to the more detailed evaluation of sector costs produced by IPM. For a discussion of the limitations and uncertainties in the SAGE analysis please see Section 5.2.6.

This section describes EPA's approach to quantify estimated avoided compliance costs in the power sector associated with this action, which includes estimates projected directly by the model and costs estimated outside the model framework. The model projections capture the avoided 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, the EPA estimates monitoring, reporting and recordkeeping (MR&R) avoided costs for affected EGUs for the timeframe of 2026 to 2047, and these costs are added to the estimated change in the total system production cost projected by IPM.

3.4 Estimated Impacts of the Final Repeal

3.4.1 Emissions Changes Assessment

Table 3-3 shows the total EGU annual emissions of CO_2 in the 2024 CPS RIA and the emissions changes of this final action. Positive values for the emission changes column reflect emissions increases. Negative values for the emission changes column reflect emissions decreases. Under both the Baseline (with CPS) and Final Repeal scenarios, nationwide emissions are generally lower than 2025 levels over the forecast period – i.e. U.S. power sector emissions are projected to decline through 2045 regardless of the imposition of the CPS.

[26] Please see section 5.2.3.1 for details on the differences between these three cost estimation methods. The last paragraph of Section 5.2.3.1 (on page 5-9) identifies four reasons why the compliance cost and social cost estimates differ. The last three of these are also reasons why the real resource and social cost estimates differ. Specifically, relative to the real resource cost estimate, the social cost estimate from the CGE model accounts for: 1) the availability of additional margins of substitution throughout the economy that are not accounted for in IPM, 2) the interaction of changes across these margins with certain pre-existing market distortions (specifically tax interactions), and 3) how changes in aggregate investment activity affect economic growth.

Table 3-3 EGU Annual CO_2 Emissions and Emission Changes (million metric tons) [11]

Annual CO_2	Total Emissions		
(million metric tons)	Baseline (with CPS)	Final Repeal	Emissions Change
2030	1,551	1,570	20
2035	1,108	1,514	406
2040	878	1,411	533
2045	720	1,206	486

Table 3-4 shows the total EGU annual emissions of NO_x, $PM_{2.5}$, Hg and SO_2 in the 2024 CPS RIA, and the emissions changes of this final action. Positive values for the emission changes column reflect emissions increases. Negative values for the emission changes column reflect emissions decreases.

Within the compliance modeling, sources within each subcategory are subject to GHG mitigation measures beginning in 2030. Forgone emission reductions peak in 2040, reflective of the full imposition of the CPS requirements and higher demand growth

In addition to the annual CO_2 increases, there will also be changes of other air emissions associated with EGUs burning fossil fuels that result from compliance strategies to reduce annual CO_2 emissions. These other emissions include the annual total changes in emissions of NO_X, SO_2, direct $PM_{2.5}$, and ozone season NO_X emissions changes. The changes in emissions are presented in Table 3-4.

Table 3-4 EGU Annual Emissions and Emissions Changes for NO_X, SO_2, Hg, and $PM_{2.5}$, and Ozone Season NO_X

Annual NO_X	Total Emissions		
(Thousand Tons)	Baseline (with CPS)	Final Repeal	Emissions Change
2030	633	646	13
2035	411	602	191
2040	316	573	257
2045	149	474	325
Ozone Season NO_X[a]	**Total Emissions**		
(Thousand Tons)	**Baseline (with CPS)**	**Final Repeal**	**Emissions Change**
2030	272	279	8
2035	181	253	71
2040	144	243	98
2045	72	212	140
Annual SO_2	**Total Emissions**		
(Thousand Tons)	**Baseline (with CPS)**	**Final Repeal**	**Emissions Change**
2030	685	695	10
2035	307	682	375
2040	262	656	394
2045	32	540	508
Annual Mercury	**Total Emissions**		
(Tons)	**Baseline (with CPS)**	**Final Repeal**	**Emissions Change**
2030	3.8	3.8	0.0
2035	3.5	4.1	0.6
2040	3.4	4.0	0.6
2045	1.5	3.3	1.9
Direct $PM_{2.5}$	**Total Emissions**		
(Thousand Tons)	**Baseline (with CPS)**	**Final Repeal**	**Emissions Change**
2030	97	96	-1
2035	90	97	7
2040	83	97	14
2045	49	79	30

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

3.4.2 Monitoring, Reporting, and Recordkeeping Costs

In this RIA, we estimate the impact of this final repeal on monitoring, reporting, and recordkeeping (MR&R) costs. This final repeal is estimated to reduce the MR&R costs incurred by states to comply with the CPS emission guidelines for existing fossil fuel fired EGUs. These MR&R cost savings are estimated to occur in 2026, as shown in Table 3-5. For details on these estimates made for purposes of this economic analysis, see the associated spreadsheet in the docket titled *PV EAV Analysis – 2026 Final Repeal.xlsx*.

Table 3-5 Impact of Final Repeal on State and Industry Annual Respondent Cost of Reporting and Recordkeeping Requirements (million 2024 dollars)

Year	2024 CPS EGs for Existing Fossil Fuel Fired Electric Generating Units		Total
	Industry	State	
2026	-	13	13
2027	-	-	-
2028	-	-	-
2029	-	-	-
2030	-	-	-
2031	-	-	-
2032	-	-	-
2033	-	-	-
2034	-	-	-
2035	-	-	-
2036	-	-	-
2037	-	-	-
2038	-	-	-
2039	-	-	-
2040	-	-	-
2041	-	-	-
2042	-	-	-
2043	-	-	-
2044	-	-	-
2045	-	-	-
2046	-	-	-
2047	-	-	-

Notes: Values have been rounded to two significant figures. These estimates are for purposes of the analysis in this RIA. For additional information, please see the spreadsheet in the docket titled *PV EAV Analysis – 2026 Final Repeal.xlsx*.

3.4.3 Compliance, Real Resource, and Social Cost Assessment

This RIA estimates that the CPS final repeal will avoid substantial compliance costs. This section presents three sets of estimates of these avoided costs. First, this section presents IPM's estimates of avoided costs to the power sector. Second, this RIA presents the IPM estimates as the real resource costs paid by society, which differ from the sector compliance costs because of the accounting for transfer payments. Third, to estimate the social costs for the economy as a whole, the EPA has used information from IPM as an input into the Agency's computable general equilibrium model, SAGE.

Table 3-6 presents IPM's estimates of changes in power sector compliance costs (i.e., the change in costs paid by the power sector). These changes in costs are presented for the representative IPM run years of 2030, 2035, 2040, and 2045 in real 2024 dollars. A negative cost reflects a projected reduction in compliance cost expenditures as a result of this action, while a positive cost denotes an increase. In addition to evaluating annual compliance cost impacts, the EPA believes that a full understanding of these impacts benefit from an evaluation of annualized costs over the 2026 to 2042 and 2026 to 2047 timeframes. Costs for these periods are annualized using IPM's real discount rate of 3.76 percent and exclude costs for years outside of each of the respective multiple-year time periods.[27, 28] This 3.76 percent discount rate is consistent with the rate used in IPM's objective function for minimizing the PV of the stream of total costs of electricity generation [29, 30] This discount rate is meant to capture the observed equilibrium market rate at which investors are willing to sacrifice present consumption for future consumption and is based on a Weighted Average Cost of Capital (WACC).

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[27] Consistent with the relationship between IPM run years and calendar years, the EPA assigned run year compliance cost estimates to all calendar years mapped to that run year. For more information, see Chapter 2 of the IPM documentation available at https://www.epa.gov/system/files/documents/2025-02/epa-2023-reference-case.pdf.

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

[29] The objective function of IPM minimizes the present value of system costs, and a discount rate is used in IPM to convert all future costs to a present value. The private discount rate adopted for modeling investment behavior should reflect the rate at which investors are willing to invest in the sector. For a general discussion of the risk and temporal preferences, tax treatments, and costs of borrowing that inform discount rates, Section 6.4 of the EPA's *Guidelines for Preparing Economic Analyses* (U.S. EPA, 2024a). The real discount rate used in EPA's Power Sector Modeling Platform 2023 Using the Integrated Planning Model, 3.76 percent, equals the real weighted average after-tax cost of capital for various ownership types and technologies. The discount rate used in EPA's modeling is invariant over time. For more information, see Chapter 10 of the *Documentation for EPA's Power Sector Modeling Platform 2023 Using the Integrated Planning Model 2023 Reference Case*, available in the docket (U.S. EPA, 2024b). The private discounting used in IPM to simulate industry behavior differs from the social discounting used to estimate the social net benefits of the regulatory action. The social discount rates used in the net benefits analysis in this RIA reflect the intertemporal preferences of society as a whole, with 3 percent representing the consumption rate of interest and 7 percent representing the social opportunity cost of capital (OMB Circular A-4 (2003), and Section 6.2 of the EPA *Guidelines* (2024a)). In contrast, as discussed in Section 5.2.1, the discount rate in SAGE varies over time and household depending on intertemporal consumption preferences. The social costs estimates from SAGE apply a discount rate of 4.5 percent, which is consistent with the internal discount rate and average capital rate in the model.

[30] "The real discount rate for all expenditures (capital, fuel, variable operations and maintenance, and fixed operations and maintenance costs) in the EPA 2023 Reference Case is 3.76%" (U.S.EPA, 2024b, p. 10-5).

Table 3-6 National Power Sector Costs (billion 2024 dollars)[31]

2026 to 2042 (Annualized)	-7.3
2026 to 2047 (Annualized)	-10
2030 (Annual)	-0.96
2035 (Annual)	-16
2040 (Annual)	-4.4
2045 (Annual)	-23

Cost savings peak in 2035 and 2045 – in 2035 CPS requirements are fully in effect, resulting in changes to the generation and capacity mix that drive higher costs, while higher demand, retiring coal capacity, and lower utilization of new efficient combined cycles drive higher costs in the later part of the forecast period.

EPA's modeling provides an estimate of the change in costs due to this final action in the electricity sector and related energy sectors (i.e., natural gas, coal mining) and allows 90 percent CCS as a control strategy. The projected change in the national power sector costs shown in Table 3-6 is the change in costs paid by the power sector because of this action. The projected change in IPM power sector costs includes the avoided cost of additional resources that are used by the sector because of the repeal, such as the cost of pollution controls, labor, materials, fuel, transport, and storage. These "real resources" constitute the changes in physical and labor inputs used by the sector because of the EPA action.

The projected change in power sector cost also includes changes in tax and subsidy payments, financing charges for new capital, and insurance. For example, when IPM projects that a new generator will be built, the power sector cost includes the cost to purchase and install and operate the generator as well as the cost to finance the generator and expected taxes and insurance that will be paid on the investment. The power sector cost also includes any production and investment subsidies or tax credits that may offset expenditures on real resources.

Most tax payments, tax credits, and subsidy payments are transfers (OMB, 2003; U.S. EPA, 2024c). Transfers are shifts in money or resources from one part of the economy (e.g., a group of individuals, firms, or institutions) to another in a way that does not affect the total

[31] A negative cost reflects a projected reduction in compliance cost expenditures as a result of this action, while a positive cost denotes an increase.

resources that are available to society. In other words, the loss to one part of the economy is exactly offset by the gain to another. Transfers should be excluded from estimates of the benefits and costs of a regulatory action (OMB, 2003; U.S. EPA, 2024c).[32]

There are two important sources of tax-related transfers included in the power sector cost analysis for this final repeal. First, the compliance costs includes production and investment taxes paid on generating resources and air pollution control equipment. Second, the analysis includes tax credits awarded for certain types of generators, energy storage, and sequestration of CO_2, the levels of which are directly and indirectly affected by this final repeal.[33] Table 3-6 presents the IPM compliance cost estimates from the perspective of the power sector, which is net of taxes paid and credits received. In contrast, Table 3-7 presents the full real resource costs of compliance with a presentation of both changes in taxes paid and credits received.

The real resource approach provides an alternative estimate of the cost savings from this final repeal, adjusting the power sector cost analysis to account for the fact that the taxes and subsidies represented in the analysis using IPM may be more accurately characterized as transfers. Whether the real resource costs are greater or less than the sectoral compliance costs depends on the net effect of changes in transfers both paid to and paid by affected sectors.

[32] Transfers themselves do affect behavior, and therefore, their presence should be accounted for when estimating the social cost, social benefits, and distributional effects of a regulatory action.
[33] See Chapters 6 and 10 of the IPM documentation (U.S. EPA 2024b), available here: https://www.epa.gov/system/files/documents/2025-02/epa-2023-reference-case.pdf. Certain credits may be limited by the total tax obligation of reporting entities or the ability to transfer them to other entities. The IPM analysis in this RIA assumes that the full value of any credits is not limited by total tax obligation of reporting entities or their ability to transfer their value.

Table 3-7 Real Resource Costs under the Final Repeal (billion 2024 dollars)

	[1]	[2]	[3]	[4]	[5]	[6]
		Change in Transfers (Credits)		Change in Transfers (Government Receipts and Other)		
	Total Power Sector Compliance Costs (Table 3-19)	CO_2 Storage Tax Credit	Clean Energy Tax Credits	Corporate Income Taxes and Other Transfers	Payments For Use of Transmissio n	Change in Real Resource Costs
2030	-0.96	-0.53	1.2	-0.45	0.049	0.078
2035	-16	-25	-0.088	-4.6	0.090	-37
2040	-4.4	-25	-0.085	-6.5	0.38	-23
2045	-23	0.00	-1.2	-7.9	0.15	-17
				3% Discount Rate		
PV (2026 to 2047)	-160	-180	-0.93	-66	2.0	-280
EAV (2026 to 2047)	-10	-11	-0.059	-4.1	0.13	-18
				7% Discount Rate		
PV (2026 to 2047)	-95	-120	0.87	-38	1.2	-180
EAV (2026 to 2047)	-8.6	-11	0.078	-3.5	0.11	-16

Notes: (1) Column [6] = [1] + [2] + [3] - [4] - [5]. (2) As presented in Table 3-19, Column [1] includes changes in power sector compliance costs; monitoring, reporting, and recordkeeping costs; and tax payments less tax credits (i.e., 45Q, 45Y, and 48E). That is, Column [1] = [6] + [5] + [4] - [2] - [3]. (3) Column [4] reports the change in tax credits payments annualized using the private cost of borrowing and book life for eligible technologies. (4) Column [4] is recovered from the difference in capital charge rates and capital recovery factors applied in IPM to new capital. (5) Present values are discounted to the 2025 analysis year while costs in individual years are not. (6) Values rounded to two significant figures.

Table 3-7 reports the changes in total sector costs, transfers, and incremental real resource costs for each IPM model year. Negative values imply reductions relative to the baseline. To estimate the incremental resource costs of this final repeal, we must identify the portion of the changes in total sector costs that are due to net changes in production and investment taxes and credits for generation and tax credits for CO_2 storage and clean energy.

To start, Column 1 of Table 3-7 shows the change in power sector costs reported in Table 3-19, which represents the expenditures that the power sector will not have to make as a result of the final repeal. Column 2 reports the projected decrease in the CO_2 storage tax credit paid to the electricity sector from this final repeal. Column 3 reports the change in clean energy credits paid to the sector. The total value of the CO_2 and clean energy tax credit changes are reported separately given their scale relative to the changes in the total amount of the other transfers.

Column 4 reports the net change in other taxes and other transfers paid by the sector (e.g., investment taxes, insurance). Column 5 reports changes in payments for energy transmission costs and capacity transfer costs, which are payments for the use of existing transmission and are therefore transfers. The projected incremental change in real resource costs presented in Column 6 is calculated as the power system cost change plus the net change in CO_2 tax credits and clean energy tax credits minus the net change in other taxes and transfers and payments for the use of transmission capacity. That is, Column 6 equals the sum of Columns 1, 2 and 3 less Columns 4 and 5. This calculation of the real resource cost provides a transfer-adjusted estimate of the incremental cost savings as a result of this final repeal (negative values indicate cost savings).

Capital costs in Columns 1 and 6 are amortized using the private cost of borrowing over the assumed book life of the capital investment. The cost of borrowing, financing period, and book life varies by technology and owner-type.[34] The 45Y and 48E tax credits[35] are implemented as a reduction to overnight capital costs in IPM.[36] For consistency with the treatment of capital in Column 1, and to retain a consistent approach to accounting for capital in Column 6, Column 3 reports the change in these tax credits annualized using the private cost of borrowing and book life for the eligible technologies.

To estimate the change in social costs of this final action, the EPA used information from IPM as an input into the Agency's economy-wide computable general equilibrium model, SAGE. As described in Section 5.2.2, the inputs to the SAGE model matched both the real resource requirements for the expected compliance pathway and the impact of net changes in tax payments on the compliance expenditures for the electricity sector. Like the real resource cost analysis summarized in Table 3-7, the economy-wide analysis is a complement to the detailed evaluation of sector costs produced by IPM. As a partial equilibrium model, IPM accounts for impacts in the directly regulated electricity sector as well as the coal and natural gas sectors but does not account for impacts in the rest of the economy. Both the real resource cost and SAGE

[34] See Chapter 10 of IPM documentation: https://www.epa.gov/system/files/documents/2025-02/epa-2023-reference-case.pdf.

[35] The Production Tax Credit is a per kilowatt-hour tax federal tax credit included under Section 45Y of the US tax code, while the Investment Tax Credit is a federal tax credit included under Section 48E of the US tax code which allows for deduction of a certain percentage of costs associated with installing qualifying property.

[36] 45Y and 48E are the Federal Production Tax Credit (PTC) and Investment Tax Credit (ITC) that some generation and storage technologies are eligible to receive in some IPM model years. These technologies include wind, solar, and battery storage.

analyses improve the characterization of regulatory costs by accounting for changes outside of the directly regulated sector.

As shown below in Section 5.2.3, in Table 5-4, the annualized reduction in social cost estimated in SAGE for the final repeal is approximately $23 billion (2024 dollars) between 2026 and 2047 using SAGE's endogenous consumption discount rate path. Note that SAGE does not currently estimate the change in social benefits and their effects on the economy from changing environmental quality. See Section 5.2 for more discussion on the economy-wide analysis with SAGE and estimates of private and social costs.

3.4.4 Impacts on Fuel Use and Prices

The imposition of the CPS was expected to result in significant GHG emissions reductions as well as impacts to the economics of the power sector. Therefore, repeal of the CPS requirements also has significant impacts relative to this counterfactual scenario. 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 2030, 2035, 2040, and 2045 IPM model run years.

Table 3-8 and Table 3-9 present the percentage changes in national coal and natural gas usage by EGUs in the 2030, 2035, 2040, and 2045 run years as projected under the model solution, solving for the least-cost production of electricity to meet demand. For details on uncertainties and limitations inherent in these estimates, please see Section 3.5.

Under the final CPS repeal scenario, current market trends are projected to persist, driven by higher levels of electricity demand and the OBBBA. Hence coal capacity declines less slowly over the forecast period, and there is continued penetration of new natural gas additions and non-emitting resources such as wind and solar. These model results are driven by the relative economics of the different types of generation options available to meet electricity demand and are broadly consistent with other publicly available forecasts such as the EIA's Annual Energy Outlook 2025[37], which also projects declining coal capacity and robust additions of natural gas, wind, solar and storage capacity.

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

Of the 174 GW of coal-fired capacity active at the end of 2024, about 150 GW have not announced retirement or coal to gas conversion by 2040. The EPA projects that under the final repeal scenario (without the CPS), 100 GW of coal are projected to be active in 2040 – reflecting higher levels of projected electricity demand and changes to subsidies for wind and solar additions under the OBBBA.

Domestic and international demand for natural gas remains strong, pushing natural gas prices higher, given the higher marginal cost of producing gas at larger volumes under the final repeal scenario (without the CPS). At the same time, wind and solar cost and performance improvements mean that wind and solar generation remains economically competitive even after subsidies are phased out. This results in continued wind and solar deployment, with higher gas and non-emitting market share driving down emissions. Emissions decline slightly over the forecast period absent the CPS requirements. Under the baseline scenario that includes the CPS, requirements on existing steam generation result in large emission reductions in 2035 driven by lower thermal generation and increased adoption of BSER technology[38], and these reductions persist over the analysis period.

Under the baseline (with CPS) scenario, coal-fired EGUs in the long-term subcategory must install 90 percent CCS by the 2035 run year. Units that elect to install CCS are projected to operate for the duration of the tax credits available for CCS under section 45Q of the US tax code (i.e. 12 years), and then cease operations once the credits are no longer available. Of the 44 GW of coal-fired EGUs that are projected to install CCS under the baseline scenario by 2035, 42 GW of capacity are projected to retire by 2045. Hence emissions such as SO_2, PM and Hg that are linked to coal-fired generation are projected increase under the final repeal scenario (without CPS), particularly in 2035 and beyond when compared with the baseline. The increase in NOx emissions under the repeal scenario (without CPS) relative to the baseline is not as pronounced given the CPS requirements induce an increase in gas generation, and shifting generation from more efficient new NGCC capacity to less efficient existing NGCC capacity.

It is important to note that as explained in section V.A. of the preamble, this level of CCS deployment would be subject to significant infrastructure and other constraints in the real world. This level of CCS installation is also not evident in announcements of real-world projects. In

[38] See Table 3-1 and Table 3-2 for additional detail on BSER technologies.

order to explore the potential impacts of CCS not, in fact, being available to deploy in either the baseline or CPS scenario, the EPA performed a sensitivity analysis[39] in order to conduct a bounding exercise around the range of possible outcomes.

Table 3-8 2030, 2035, 2040 and 2045 Projected U.S. Power Sector Coal Use

		Million Tons		Percent Change from Baseline
	Year	Baseline (With CPS)	Final Repeal (No CPS)	
Appalachia	2030	72	70	-3%
Interior		62	61	-2%
Waste Coal		7	7	0%
West		242	259	7%
Total		383	398	4%
Appalachia	2035	50	62	23%
Interior		41	57	37%
Waste Coal		5	7	43%
West		169	267	58%
Total		266	392	48%
Appalachia	2040	52	63	20%
Interior		35	53	51%
Waste Coal		3	3	0%
West		154	266	73%
Total		244	385	58%
Appalachia	2045	0	39	N/A
Interior		4	30	753%
Waste Coal		0	3	N/A
West		11	219	1814%
Total		15	291	1832%

[39] *See* "IPM Sensitivity Runs Memo" available in the docket for this action

Table 3-9 2030, 2035, 2040 and 2045 Projected U.S. Power Sector Natural Gas Use

	Trillion Cubic Feet (TCF)		Percent Change from Baseline
Year	**Baseline (With CPS)**	**Final Repeal (No CPS)**	**Final Repeal (No CPS)**
2030	14.6	14.4	-1.6%
2035	18.0	16.4	-8.9%
2040	14.4	14.7	1.9%
2045	12.2	11.8	-3.1%

Table 3-10 and Table 3-11 present the projected coal and natural gas prices in 2030, 2035, 2040 and 2045, as well as the percent change from the baseline projected due to the illustrative scenario. As shown in Table 3-8, we estimate demand for coal by the U.S. power sector to be higher under the Final Repeal scenario than under baseline (with CPS) scenario. Consistent with this higher demand, we estimate higher prices for delivered coal, as reflected in Table 3-10. By 2030, the final repeal scenario shows lower levels of gas consumption and prices relative to the baseline scenario, since the baseline scenario includes reductions in coal generation stemming from requirements on medium-term coal fired electricity generating steam units which are offset by higher levels of gas generation. In 2035, decreases in gas consumption under the final repeal scenario are highest relative to the baseline scenario, stemming from the requirements on long-term coal fired electricity generating steam units and the NSPS under the baseline, which reduce generation from coal-fired EGUs and new combustion turbines, and are offset by increased generation from existing natural gas fired generation. Impacts lessen in 2040 onwards as both scenarios show higher levels of renewable electricity generation, and less gas and coal generation.

Growing liquefied natural gas (LNG) exports result in tighter natural gas markets, particularly in 2035 and beyond, while renewable electricity cost and performance continue to improve. At the same time, requirements on new combustion turbines result in fewer new NGCCs that run at baseload levels under the baseline. This means that as thermal generation falls, it is filled by a combination of higher existing gas and new renewable electricity generation, tamping down on the increase in gas consumption relative to the repeal scenario.

Table 3-10 2030, 2035, 2040 and 2045 Projected Minemouth and Power Sector Delivered Coal Price (2024 dollars)

		2024$/MMBtu		Percent Change from Baseline
		Baseline (With CPS)	Final Repeal (No CPS)	Final Repeal (No CPS)
Minemouth	2030	1.33	1.42	7%
Delivered		2.15	2.24	4%
Minemouth	2035	1.35	1.47	9%
Delivered		2.08	2.30	10%
Minemouth	2040	1.50	1.59	6%
Delivered		2.16	2.38	10%
Minemouth	2045	1.79	1.67	-7%
Delivered		1.88	2.39	27%

Table 3-11 2030, 2035, 2040 and 2045 Projected Henry Hub and Power Sector Delivered Natural Gas Price (2024 dollars)

		2024$/MMBtu		Percent Change from Baseline
		Baseline (With CPS)	Final Repeal (No CPS)	Final Repeal (No CPS)
Henry Hub	2030	4.21	4.12	-2%
Delivered Natural Gas		4.27	4.18	-2%
Henry Hub	2035	5.73	5.26	-8%
Delivered Natural Gas		5.72	5.23	-9%
Henry Hub	2040	5.68	5.72	1%
Delivered Natural Gas		5.65	5.69	1%
Henry Hub	2045	6.08	5.96	-2%
Delivered Natural Gas		6.05	5.93	-2%

Gas capacity is higher under the baseline (with CPS) scenario as a result of greater Natural Gas Combustion Turbine (NGCT) buildout. These NGCT units operate at low capacity factors, which means gas consumption is similar between the two scenarios, as is natural gas price. However, new Natural Gas Combined Cycle (NGCC) additions operate at lower levels of utilization as a result of the NSPS requirements – as a result less efficient, existing NGCC units operate at higher utilization levels.

Table 3-12 presents the projected percentage changes in the amount of electricity generation in 2030, 2035 and 2040 by fuel type. Consistent with the fuel use projections and emissions trends above, EPA's modeled solution projects an overall shift from coal to gas and renewables under the baseline scenario, and these trends persist under the final repeal scenario. The projected impacts are highest in 2035 and 2040. The 45Q tax credit[40] is available for 12 years within the modeling,[41] after which point units no longer receive tax credits and must dispatch based on unsubsidized operating costs.

Table 3-12 2030, 2035, 2040 and 2045 Projected U.S. Generation by Fuel Type

		Generation (TWh)		Percent Change from Baseline
	Year	Baseline (with CPS)	Final Repeal (Without CPS)	
Coal	2030	694	727	5%
Coal with CCS		13	7	-43%
Coal with Gas co-firing		20	0	-98%
Natural Gas		2,070	2,073	0%
Hydrogen Co-firing		0	0	-
Natural Gas with CCS		0	0	-
Nuclear		743	743	0%
Hydro		301	297	-1%
Non-Hydro RE		1,204	1,200	0%
Oil/Gas Steam		27	28	4%
Other		29	29	0%
Grand Total		5,100	5,105	0%
Coal	2035	43	563	1207%
Coal with CCS		299	103	-65%
Coal with Gas co-firing		25	0	-100%
Natural Gas		2,488	2,469	-1%
Hydrogen Co-firing		0	0	-
Natural Gas with CCS		65	45	-31%
Nuclear		675	675	0%
Hydro		320	317	-1%
Non-Hydro RE		2,011	1,778	-12%
Oil/Gas Steam		13	6	-56%
Other		29	29	-1%

[40] This is a tax subsidy expressed in $/ton available for qualifying facilities that capture and sequester carbon under section 45Q of the US tax code.
[41] The EPA assumes a 12-year booklife for CCS consistent with the duration of the 45Q tax credit

	Year	Generation (TWh)		Percent Change from Baseline
		Baseline (with CPS)	**Final Repeal (Without CPS)**	
Grand Total		5,968	5,985	0%
Coal	2040	5	553	10141%
Coal with CCS		299	103	-65%
Coal with Gas co-firing		0	0	-
Natural Gas		2,106	2,279	8%
Hydrogen Co-firing		0	0	3%
Natural Gas with CCS		65	45	-31%
Nuclear		638	638	0%
Hydro		345	341	-1%
Non-Hydro RE		3,007	2,515	-16%
Oil/Gas Steam		4	3	-8%
Other		27	27	-1%
Grand Total		6,495	6,503	0%
Coal	2045	5	508	10287%
Coal with CCS		14	14	2%
Coal with Gas co-firing		0	0	-
Natural Gas		1,854	1,896	2%
Hydrogen Co-firing		0	0	-31%
Natural Gas with CCS		22	4	-81%
Nuclear		523	528	1%
Hydro		347	346	0%
Non-Hydro RE		3,993	3,467	-13%
Oil/Gas Steam		3	3	-7%
Other		27	27	-1%
Grand Total		6,788	6,793	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. “Hydrogen Co-firing” reflects the amount of electricity generated at turbines using Hydrogen as fuel, and “Coal with Gas co-firing” reflects the amount of electricity generated at coal power plants using natural gas.

Table 3-13 presents the projected percentage changes in the amount of generating capacity in 2030, 2035, 2040 and 2045 by primary fuel type. In 2035, the CPS is assumed to be in effect under the baseline scenario. In order to comply with the CPS requirements in 2035, 9 GW of coal-fired EGUs are projected to co-fire with natural gas, 44 GW of coal-fired EGUs are projected to install CCS, 6 GW are projected to convert to gas, and 68 GW are projected to retire. Total coal capacity is projected to be 124 GW in 2030, and falls to 3 GW by 2045 under the baseline scenario. These investments are not required under the repeal scenario, and as a result total coal capacity in 2030 is projected to be 127 GW and falls to 85 GW by 2045.

By 2030 the repeal of the CPS requirements is projected to result in an additional 1 GW of avoided coal retirements, by 2035 an incremental 32 GW of avoided coal retirements and by 2040 an incremental 41 GW of coal avoided retiring relative to the baseline scenario. By 2045 the repeal of the CPS requirements is projected to result in an incremental 68 GW of avoided coal retirements relative to the baseline.

IPM endogenously estimates the capacity credit (i.e. the accredited capacity that can count towards meeting the resource adequacy constraints within the model) for wind, solar, and storage as a function of penetration.[42] The modeling performed for this analysis projects 87 GW fewer renewable capacity additions (consisting of 79 GW of solar and 8 GW of wind builds) and 2 GW of storage are projected by 2035 in the final repeal scenario as compared to the baseline scenario. Under the final repeal scenario, 154 GW of economic NGCC additions occur by 2035 (matching baseline additions), and 35 GW of economic NGCT additions occur by 2035 (as compared to 53 GW under the baseline scenario). Under the baseline, 7 GW of new NGCC units are projected to install CCS, while under the final repeal scenario 4 GW of new NGCC units are projected to install CCS.

Table 3-13 2030, 2035, 2040 and 2045 Projected U.S. Capacity by Fuel Type

		Capacity (GW)		Percent Change from Baseline
	Year	Baseline (With CPS)	Final Repeal (No CPS)	
Coal	2030	113	126	11%
Coal with CCS		2	1	-42%
Coal with Gas co-firing		9	0	-99%
Natural Gas		542	524	-3%
Natural Gas with CCS		0	0	
Nuclear		93	93	0%
Hydro		104	104	0%
Non-Hydro RE		432	428	-1%
Oil/Gas Steam		68	66	-3%

[42] For details, please see chapter 4 of the IPM documentation, available here: https://www.epa.gov/system/files/documents/2025-02/epa-2023-reference-case.pdf.

	Year	Capacity (GW)		Percent Change from Baseline
		Baseline (With CPS)	Final Repeal (No CPS)	
Other		6	6	0%
Grand Total		1,368	1,347	-2%
Coal	2035	1	85	10240%
Coal with CCS		44	15	-66%
Coal with Gas co-firing		9	0	-99%
Natural Gas		642	627	-2%
Natural Gas with CCS		9	6	-31%
Nuclear		84	84	0%
Hydro		108	108	0%
Non-Hydro RE		704	616	-12%
Oil/Gas Steam		45	38	-17%
Other		6	6	-1%
Grand Total		1,651	1,584	-4%
Coal	2040	1	85	10735%
Coal with CCS		44	15	-66%
Coal with Gas co-firing		0	0	
Natural Gas		717	691	-4%
Natural Gas with CCS		9	6	-31%
Nuclear		80	80	0%
Hydro		112	111	0%
Non-Hydro RE		1,008	850	-16%
Oil/Gas Steam		40	37	-8%
Other		6	6	-1%
Grand Total		2,016	1,881	-7%
Coal	2045	1	83	11014%
Coal with CCS		2	2	-2%
Coal with Gas co-firing		0	0	
Natural Gas		817	751	-8%
Natural Gas with CCS		7	4	-47%
Nuclear		66	66	0%
Hydro		112	111	0%
Non-Hydro RE		1,325	1,153	-13%
Oil/Gas Steam		40	37	-8%
Other		6	6	-1%
Grand Total		2,376	2,213	-7%

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

The EPA estimated the change in the retail price of electricity (2024 dollars) using the Retail Price Model (RPM).[43] The RPM was developed by the consultancy ICF for the EPA and uses the IPM estimates of changes in the cost of generating electricity to estimate the changes in average retail electricity prices. The prices are average prices over consumer classes (i.e., consumer, commercial, and industrial) and regions, weighted by the amount of electricity used by each class and in each 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).[44]

Table 3-14, Table 3-15, Table 3-16, and Table 3-17 present the projected percentage changes in the retail price of electricity for the illustrative scenario in 2030, 2035, 2040 and 2045, respectively. Consistent with other projected impacts presented above, average retail electricity prices at both the national and regional level are projected to experience the largest impacts in 2035. Under the CPS requirements, coal-fired EGUs must install CCS by 2035, and phase II of the NSPS (requiring new NGCC additions to meet an emission rate consistent with 90 percent CCS or operate below baseload) results in significant additional costs to the system, which flow through to purchasers of electricity in the form of higher rates. In 2030, national electricity rates are projected to increase 0.7 percent relative baseline levels, or an increase of 1 mills/kWh (2024 dollars). In 2035, the EPA estimates that this action will result in a 5.8 percent decrease in national average retail electricity price, or by about 7.81 mills/kWh (2024 dollars). In 2040, the EPA estimates that this action will result in a 1.1 percent decrease in national average retail electricity price, or by about 1.49 mills/kWh. In 2045, the EPA estimates that this action will result in a 2.6 percent decrease in national average retail electricity price, or by about 3.43 mills/kWh. At the national level, this repeal is therefore expected to reduce retail electricity rates 2.2 percent on average over the 2030-2045 period.

[43] See documentation available at: https://www.epa.gov/airmarkets/retail-price-model
[44] See documentation available at: https://www.eia.gov/outlooks/aeo/nems/documentation/electricity/pdf/EMM_2022.pdf

Table 3-14 Average Retail Electricity Price by Region, 2030

All Sector	2030 Average Retail Electricity Price (2024 mills/kWh)		Percent Change from Baseline
Region	Baseline (With CPS)	Final Repeal (No CPS)	Final Repeal (No CPS)
TRE	120	122	2%
FRCC	121	120	0%
MISW	121	120	-1%
MISC	113	114	1%
MISE	153	158	3%
MISS	110	109	0%
ISNE	227	221	-3%
NYCW	306	309	1%
NYUP	197	202	2%
PJME	169	173	2%
PJMW	124	127	2%
PJMC	122	126	3%
PJMD	115	118	3%
SRCA	115	115	0%
SRSE	113	113	0%
SRCE	101	101	0%
SPPS	97	99	2%
SPPC	111	110	0%
SPPN	84	83	-1%
SRSG	132	132	0%
CANO	186	186	0%
CASO	222	223	1%
NWPP	113	114	1%
RMRG	117	108	-7%
BASN	132	135	2%
NATIONAL	134	135	0.7%

Table 3-15 Average Retail Electricity Price by Region, 2035

All Sector	2035 Average Retail Electricity Price (2024 mills/kWh)		Percent Change from Baseline
Region	**Baseline (With CPS)**	**Final Repeal (No CPS)**	**Final Repeal (No CPS)**
TRE	117	106	-9%
FRCC	128	124	-3%
MISW	126	122	-3%
MISC	110	104	-6%
MISE	140	124	-12%
MISS	112	107	-4%
ISNE	215	207	-4%
NYCW	282	263	-7%
NYUP	182	165	-9%
PJME	165	149	-10%
PJMW	130	119	-9%
PJMC	133	116	-12%
PJMD	119	102	-14%
SRCA	119	116	-2%
SRSE	117	116	-1%
SRCE	105	102	-3%
SPPS	100	96	-4%
SPPC	107	105	-2%
SPPN	90	87	-3%
SRSG	135	131	-3%
CANO	186	179	-4%
CASO	224	219	-2%
NWPP	113	110	-2%
RMRG	122	108	-11%
BASN	138	136	-2%
NATIONAL	134	127	-5.8%

Table 3-16 Average Retail Electricity Price by Region, 2040

All Sector	2040 Average Retail Electricity Price (2024 mills/kWh)		Percent Change from Baseline
Region	**Baseline (With CPS)**	**Final Repeal (No CPS)**	**Final Repeal (No CPS)**
TRE	107	106	-1%
FRCC	124	123	0%
MISW	117	114	-2%
MISC	106	106	0%
MISE	130	126	-3%
MISS	108	107	-1%
ISNE	223	222	-1%
NYCW	290	290	0%
NYUP	190	190	0%
PJME	157	150	-4%
PJMW	124	123	-1%
PJMC	118	121	2%
PJMD	114	107	-6%
SRCA	114	114	-1%
SRSE	113	113	0%
SRCE	103	102	-1%
SPPS	94	94	0%
SPPC	98	98	0%
SPPN	85	84	-1%
SRSG	128	126	-2%
CANO	186	186	0%
CASO	219	219	0%
NWPP	114	116	2%
RMRG	117	107	-8%
BASN	132	132	0%
NATIONAL	130	128	-1.1%

Table 3-17 Average Retail Electricity Price by Region, 2045

All Sector	2045 Average Retail Electricity Price (2024 mills/kWh)		Percent Change from Baseline
Region	Baseline (With CPS)	Final Repeal (No CPS)	Final Repeal (No CPS)
TRE	103	101	-1%
FRCC	126	123	-2%
MISW	111	105	-5%
MISC	110	102	-7%
MISE	130	128	-2%
MISS	112	109	-3%
ISNE	221	220	0%
NYCW	282	283	0%
NYUP	184	183	0%
PJME	157	153	-2%
PJMW	128	125	-2%
PJMC	126	125	-1%
PJMD	105	101	-4%
SRCA	117	112	-4%
SRSE	116	111	-4%
SRCE	102	100	-2%
SPPS	97	95	-2%
SPPC	109	101	-8%
SPPN	98	86	-12%
SRSG	122	118	-4%
CANO	189	188	-1%
CASO	221	219	-1%
NWPP	119	116	-2%
RMRG	115	106	-8%
BASN	134	126	-6%
NATIONAL	130	127	-2.6%

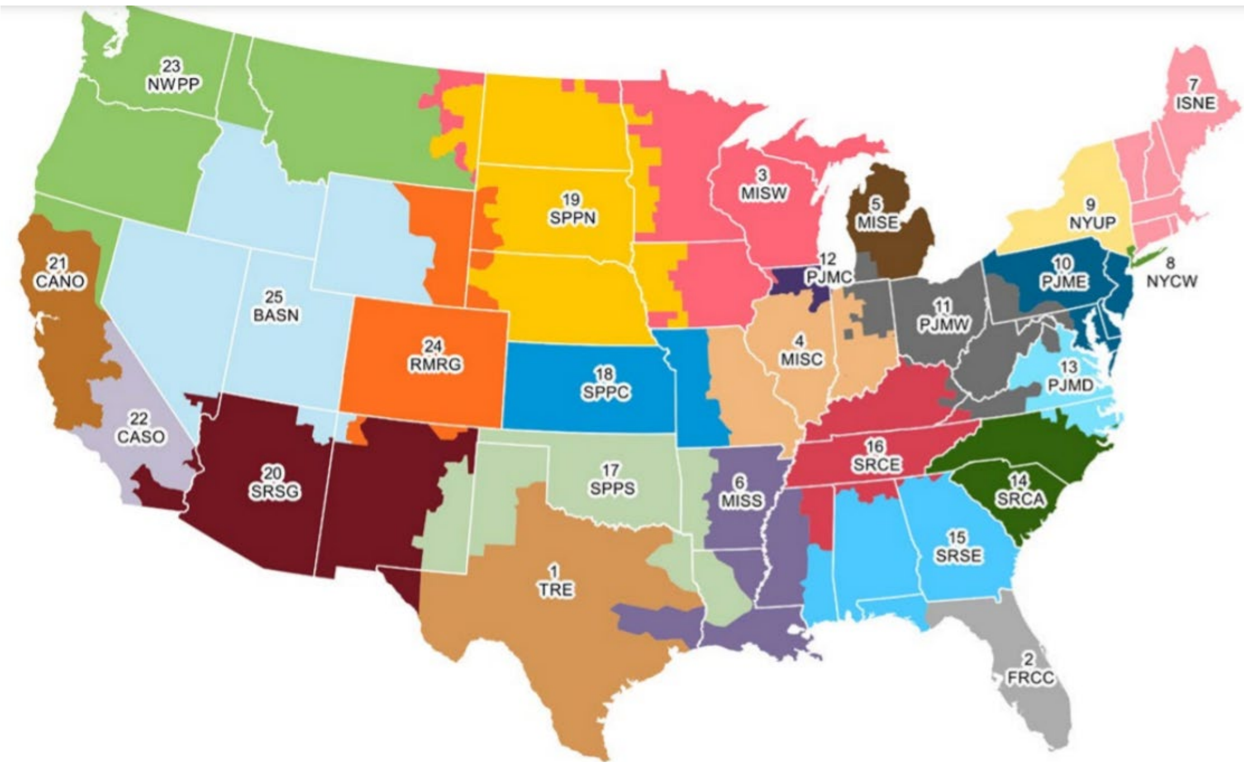

Figure 3-1 Electricity Market Module Regions
Source: EIA (http://www.eia.gov/forecasts/aeo/pdf/nerc_map.pdf)

The change in retail electricity prices reported Table 3-18 is a national average. The change in electricity retail prices were projected using outputs of IPM. Overall, the EPA projects lower average regional electricity prices over most of the modeling timeframe under the final repeal scenario than under the baseline (with CPS) scenario. Regionally, the EPA projects small increases and decreases in the average regional electricity price in 2030 and decreases between 1 percent and 14 percent in 2035 as a result of this action. In regions with high levels of data center demand and high levels of coal and gas fired generation such as PJM and ERCOT, projected reductions in retail rates are more pronounced than in regions with lower levels of demand growth and lower levels of coal and gas fired generation. Estimating higher costs and retail rates in a single year under a deregulatory action is possible given the assumption of perfect foresight on the part of power sector operators, where the model minimizes the discounted PV of a stream of annual total cost of generation over a multi-decadal time period. Relative to the baseline (with CPS), the model is projecting more combustion turbine deployment in the early years and more battery storage in subsequent years, which manifests as lower incremental production costs and retail prices in those years. This results both from the assumption of perfect foresight as well as

EPA's assumption that incremental combined cycle construction is unavailable at the beginning of the model horizon (reflecting assumptions on the lead time necessary to construct those assets). New gas generating capacity is economic due to the expected demand growth, and the model is balancing NGCC deployment timing constraints, the relative costs of NGCT and battery storage, and the reduced future value of NGCC capacity in the baseline scenario where the NSPS requirements constrain the operation of this new capacity. The discounted PV of costs over the full model horizon are lower under the final repeal scenario than the baseline (with CPS) scenario.

It is important to note that there are several reasons that the differences in the 2030 projections may vary from real world impacts. First, even though turbine and battery projects can physically be built in that timeframe, planning horizons are likely longer. Second, what we are seeing in the real world is that companies are trying to maximize both battery and combustion turbine build out regardless of the fact that prices for batteries may be cheaper in the future.

Table 3-18 National Impacts on Fuel Prices, Fuel Consumption, and Electricity Prices

		2030	2035	2040	2045
Retail electricity prices (2024 mills/kWh)	Baseline (with CPS)	134	134	130	130
	Final Repeal	135	127	128	127
	Percentage Change (%)	0.7%	-5.8%	-1.1%	-2.6%
Average price of coal delivered to the power sector (2024 $/MMBtu)	Baseline (with CPS)	2.1	2.1	2.2	1.9
	Final Repeal	2.2	2.3	2.4	2.4
	Percentage Change (%)	4.3%	10.5%	10.0%	27.3%
Coal production for power sector use (million tons)	Baseline (with CPS)	379	264	245	19
	Final Repeal	393	388	386	293
	Percentage Change (%)	4%	47%	57%	1405%
Price of natural gas delivered to power sector (2024$/MMBtu)	Baseline (with CPS)	4.3	5.7	5.7	6.0
	Final Repeal	4.2	5.2	5.7	5.9
	Percentage Change (%)	-2.2%	-8.5%	0.6%	-1.9%
Price of average Henry Hub (spot) (2024$/MMBtu)	Baseline (with CPS)	4.2	5.7	5.7	6.1
	Final Repeal	4.1	5.3	5.7	6.0
	Percentage Change (%)	-2.2%	-8.2%	0.7%	-1.9%
Natural gas use for electricity generation (TCF)	Baseline (with CPS)	15	18	14	12
	Final Repeal	14	16	15	12
	Percentage Change (%)	-1.6%	-8.9%	1.9%	-3.1%

3.4.5 Total Compliance Costs

Table 3-19 presents the present values (PVs) and equivalent annualized values (EAVs), calculated for the 2026 to 2047 timeframe.

Table 3-19 Present Value and Equivalent Annualized Value Estimates of Costs (billion 2024 dollars, discounted to 2025) [a]

Power Sector Generating Costs		Monitoring, Reporting, and Recordkeeping Costs		Total Costs	
PV	**EAV**	**PV**	**EAV**	**PV**	**EAV**
		3% Discount Rate			
-160	-10	-0.013	-0.001	-160	-10
		7% Discount Rate			
-95	-8.6	-0.012	-0.001	-95	-8.6

Notes: (1) Values have been rounded to two significant figures, and some are presented to no more than three decimal places. (2) Values may not appear to add correctly due to rounding. (3) The PV and EAV presented in this table are based on a 22-year analytic timeframe (i.e., 2026 to 2047) using a 2025 present value year and beginning-of-period discounting. For E.O. 14192 regulatory accounting purposes, the EPA has prepared an alternative analysis that estimates costs over a 34-year analytic timeframe covering 2026 to 2059. To do so, the EPA uses the power sector compliance costs for 2048 to 2059 from the 2050 and 2055 model year projections located in the docket. For this rule, the EPA projects that the estimated present value and annualized value of the cost savings over this discrete timeframe are approximately $102.12 billion and $7.15 billion, respectively (7% discount rate; 2024$, 2024 present value year; 2026 to 2059 time horizon; and end-of-period discounting, where the annualized value is calculated in perpetuity).

3.5 Limitations and Uncertainties

EPA's modeling is based on expert judgment concerning 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 assessment of the cost of implementing the rules for the power sector if CCS were widely available. These costs are generated from rigorous economic modeling of anticipated changes in the power sector due to implementation of the rule.

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

Electricity demand: The analysis includes an assumption for future electricity demand. This is based on AEO 2025 reference case with incremental demand representing the EPA estimates of electric vehicle demand and demand associated with data center applications, which reflects the most up to date information available at the time of this analysis.[45] To the extent electric demand is higher or lower, it may increase/decrease the projected future thermal/renewable composition of the fleet. Hence higher demand, all else equal, may result in fewer expected retirements, while a different load shape could incentivize different levels of renewable energy penetration.

Natural gas supply and demand: The baseline includes significant growth in LNG exports, driving tighter natural gas prices. 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, renewable energy and nuclear units).

Longer-term planning by utilities: To account for recent changes in retirement announcements by EGU owners and operators, the EPA has reverted to reflecting firm retirements in the model based on EIA-860 data and no longer supplementing these with other announcements of retirements by owners and operators. However, it is possible that decisions reflected in the EIA data may be revised in light of rapidly evolving market conditions.

One Big Beautiful Bill Act (OBBBA): The OBBBA was passed in July of 2025. In order to illustrate the impact of the OBBBA on this rulemaking, the EPA included a baseline that incorporates key provisions of the OBBBA as well as imposing the CPS requirements on that baseline. However, additional effects of the OBBBA beyond those modeled in this RIA could result in a change in projected system compliance costs and emissions outcomes.[46]

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 $2.0/kg. The model does not track any upstream emissions[47] associated with the production of hydrogen, nor any incremental electricity demand associated with its production. The incorporation of

[45] For details, see chapter 3 of the IPM documentation available at: https://www.epa.gov/power-sector-modeling
[46] For details of OBBBA representation in this analysis please see IPM documentation, available at: https://www.epa.gov/power-sector-modeling
[47] IPM does not track upstream emissions for any modeled fuels.

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.

Carbon Capture and Sequestration (CCS): The EPA's modeling of CCS is inclusive of the cost of installation and operating capture technology and includes heat rate and capacity penalties to account for the parasitic load of the capture equipment. The costs also reflect the cost of transport and storage of captured CO_2 based on the distance between CO_2 production and storage sites.

As detailed in Section IV.A.1 and IV.C.1 of the final rule preamble, 90 percent CO_2 capture from fossil fuel-fired EGUs (i.e., coal-fired steam generating units and new baseload stationary combustion turbines) and, therefore, 90 percent CCS from fossil fuel-fired EGUs have not been adequately demonstrated. Consequently, CCS is unable to achieve the degree of emission limitation prescribed by the CPS (i.e., based on 90 percent CCS), and therefore, would not be a control technology capable of compliance with the requirements of the CPS. To evaluate the potential extent of this impact, the EPA conducted a sensitivity analysis where we disallowed CCS adoption in the power sector.

Another potential source of uncertainty is in the timeline to deploy the infrastructure (including capture equipment, pipelines, and sequestration sites) for CCS. In general, the capture, pipeline, and sequestration infrastructure necessary for 90 percent CCS for the fleet of existing coal-fired steam generating units and any new base load combustion turbines does not currently exist. The necessary infrastructure would need to be broadly deployed, and there are potential challenges that could exist for sources (e.g., pipeline permitting and right-of-way) that may not be able to be resolved. As detailed in section IV of the final rule preamble, it is unlikely the infrastructure necessary for CCS can be deployed by the January 1, 2032, compliance date. The sensitivity analysis[48] where we disallowed CCS adoption in the power sector highlights the extent of possible outcomes.[49]

[48] *See* "IPM Sensitivity Runs Memo" available in the docket for this action
[49] The EPA notes that, for the reasons discussed in section IV of the final rule preamble, we did not perform a technical evaluation of whether lower levels of CO_2 capture efficiency have been adequately demonstrated or evaluate later compliance dates that would impact the achievability of the degree of emission limitation.

Representation of ELG and CCR in the baseline: The baseline includes modeling to capture the finalized 2020 Effluent Limitation Guidelines (ELG), and it also incorporates information provided by owners of affected facilities to state permitting authorities in October 2021 that indicate their likely compliance pathway, including retirement by 2028. Potential future incorporation of this information may result in additional coal plant retirements in an updated baseline scenario, which could affect modeled costs and benefits of the rules depending on the extent that these retirements occur before compliance deadlines for this action. Similarly, the baseline accounts for the effect of expected compliance methods for the 2020 CCR Rule. It is possible that the waste streams of coal plants are subject to multiple rules listed above, and that the interactions between these requirements may alter compliance behavior that would likely occur under any of the rules in isolation, i.e. plants may adopt compliance methods that are different than those represented in the baseline.

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 scenario similarly, and therefore, the impact on the incremental projections (reflecting the potential costs/benefits of the regulation) would be more limited and are not likely to result in notable changes to the assessment of this action described here. While it is important to recognize these key areas of uncertainty, they do not change the EPA's overall confidence in the estimated impacts of the analysis presented in this section. The EPA continues to monitor industry developments and makes appropriate updates to the modeling platforms in order to reflect the best and most current data available.

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4 BENEFITS

4.1 Introduction

This section describes the methods used to quantify changes in concentrations of ozone and $PM_{2.5}$ from EGUs and describe impacts of those changes. This analysis uses methodology for determining air quality changes that has been used in the RIAs from multiple previous proposed and final rules. The approach involves developing spatial fields of air quality across the U.S. for baseline and one final action scenario for 2030, 2035, 2040 and 2045 using nationwide photochemical source apportionment modeling and related analyses.

Though the final rule is likely to also yield health impacts associated with changes in pollutants other than ozone and $PM_{2.5}$, data limitations (particularly at low concentrations, as discussed further in Section 4.2) prevented us from characterizing the value of those reductions. In addition, this RIA does not include monetized benefits from changes in pollutants in other media, such as water effluents. We qualitatively discuss these unquantified benefits in section 4.3.

Consistent with E.O. 14154 "Unleashing American Energy" (90 FR 8353, January 20, 2025) and the memorandum titled "Guidance Implementing Section 6 of Executive Order 14154, Entitled 'Unleashing American Energy,'" the EPA did not monetize benefits associated with CO_2 emissions changes.[50] For a brief discussion of uncertainties and limitations associated with monetizing CO_2-related domestic climate benefits, see Section 6.4.

4.2 Criteria Pollutant Impacts

Historically, the EPA estimated the monetized benefits of avoided $PM_{2.5}$- and ozone-related impacts, which accounted for most, if not all, of the monetized benefits of many air regulations–even when the regulation was not regulating $PM_{2.5}$ or ozone–within Regulatory Impact Analyses. The Office of Management and Budget (OMB), in its annual report of the Benefits and Costs of Federal Regulations, routinely provides estimates that the monetized

[50] The memorandum titled "Guidance Implementing Section 6 of Executive Order 14154, Entitled 'Unleashing American Energy'" is found here: https://www.whitehouse.gov/wp-content/uploads/2025/02/M-25-27-Guidance-Implementing-Section-6-of-Executive-Order-14154-Entitled-Unleashing-American-Energy.pdf

benefits from reducing $PM_{2.5}$ and/or ozone exceed hundreds of millions or even billions of dollars and result in most of the monetized benefits from Federal regulations.

In previous Regulatory Impact Analyses (RIAs) and memos, the Agency's approach to estimating the impacts to human health of the changes in concentrations of ozone and $PM_{2.5}$ relied substantially on information from the Integrated Science Assessments for ozone and particulate matter (e.g., (U.S. EPA, 2019b, 2020a, 2020b, 2021, 2022b). These documents synthesize the toxicological, clinical, and epidemiological evidence to determine whether PM and ozone are causally related to an array of adverse human health outcomes associated with either acute (i.e., hours or days-long) or chronic (i.e., years-long) exposure; for each outcome, the ISA reports this relationship to be causal, likely to be causal, suggestive of a causal relationship, inadequate to infer a causal relationship or not likely to be a causal relationship. The ISAs reflect the Agency most up-to-date evaluation of the strength and limitations of the available scientific evidence, and clearly identify the health and welfare endpoints for which the evidence is strongest. The Agency continues to focus on these endpoints in considering how regulatory actions may impact public health and welfare. Historically, the Agency has estimated the incidence of air pollution effects for those health endpoints that the ISA classified as either causal or likely-to-be-causal and these endpoints are shown in Table 4-1. The table below omits welfare effects such as acidification and nutrient enrichment.

Table 4-1 Health Effects of Ambient Ozone and $PM_{2.5}$

Category	Effect	Causal/Likely-to-be-causal	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)	✓	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)	✓	PM ISA
	Stroke (ages 65-99)	✓	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	✓	PM ISA
	Other respiratory effects	✓	PM ISA
	Other nervous system effects	✓	PM ISA
	Cancer	✓	PM ISA
	Reproductive and developmental effects	—	PM ISA
	Metabolic effects	—	PM ISA
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
	Metabolic effects (e.g., diabetes)	✓	Ozone ISA

For regulatory analyses, the Agency estimated changes in health effects in response to modeled air quality changes for most health endpoints identified as causal or likely-to-be-causal in Table 4-1. Some endpoints were not quantified due to data availability limitations, such as for other cardiovascular/respiratory/nervous system effects. The environmental Benefits Mapping and Analysis Program—Community Edition (BenMAP-CE) software program was used to quantify counts of premature deaths and illnesses attributable to photochemical modeled changes in annual mean $PM_{2.5}$ and summer season average ozone. This approach to estimating health impacts involved two major steps: (1) developing spatial fields of air quality across the U.S. for the baseline and regulatory scenarios using nationwide photochemical source apportionment modeling and related analyses; and (2) using these spatial fields in BenMAP-CE to quantify selected endpoints under each scenario and each year as compared to the baseline in that year while accounting for the changes in population size, income growth, and baseline incidence and prevalence rates.

Figure 4-1 summarizes the key data inputs and modeling steps for estimating the health impacts of a regulatory impact analysis using $PM_{2.5}$ inputs as an example.

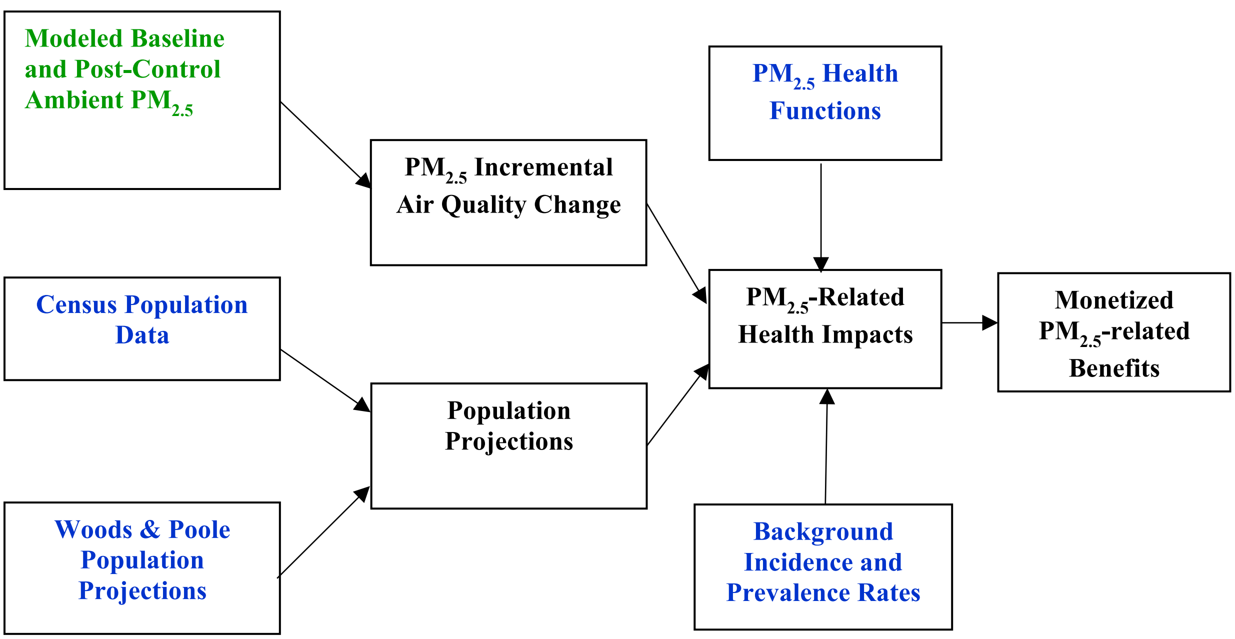

Figure 4-1 Data Inputs and Outputs for the BenMAP-CE Model Using $PM_{2.5}$ as an Example

As the diagram above illustrates, the approach for estimating $PM_{2.5}$ and O3 benefits included health effect risk estimates from epidemiologic studies, population data, population growth estimates, economic data for monetizing risk reductions, and assumptions regarding the future state of the world (e.g., on-the-books regulations). Each of these inputs has unique uncertainties associated with it. When the uncertainties from each stage of the analysis are compounded, even small uncertainties can have large effects on the total quantified benefits. Where possible, the EPA in the past has attempted to quantitatively assess uncertainty in each input parameter. In some cases, quantitative analysis has not been possible due to lack of data, so the Agency instead characterized the sensitivity of the results to alternative plausible input parameters. And, for some inputs into the benefits analysis, such as the air quality data, we lacked the data to perform either a quantitative uncertainty analysis or sensitivity analysis.

Throughout prior regulatory impact analyses, the EPA acknowledged these significant uncertainties around input parameters and employed various techniques for characterizing the resulting uncertainty in estimates of regulatory impacts. For example, the Agency has estimated the fraction of avoided health effects occurring at various concentration ranges, conducted sensitivity analyses, and employed alternate concentration-response assumptions to show how much estimates could vary depending on which assumptions and inputs were used in primary estimates vs. sensitivity estimates.

Chapter 6 of the EPA Health Benefits TSD, Estimating $PM_{2.5}$- and Ozone-Attributable Health Benefits: 2024 Update, details our approach to characterizing uncertainty associated with the estimation of $PM_{2.5}$ and O_3 benefits in both quantitative and qualitative terms (U.S.EPA, 2024). Some of the key types of uncertainty highlighted in this chapter include:

- Statistical uncertainty around the risk estimate
- Uncertainty around low concentration exposures and the potential for thresholds
- Uncertainty in exposure estimates
- Co-pollutant confounding
- Confounding by other individual risk factors
- Effect modification
- Application of risk estimates to other locations and populations
- Uncertainties regarding at-risk populations
- Baseline incidence rate uncertainties

- Economic valuation estimate uncertainties (e.g. income elasticity of willingness to pay, statistical estimates of VSL, Alzheimer's and Parkinson's onset lifetime costs)
- Unquantified uncertainties (e.g. causality determination, estimating and assigning exposures in epidemiology studies, risk attributable to long-term and short-term exposures, shape of the concentration-response relationship)

Despite substantial investments by the EPA in approaches to characterizing uncertainties, the regulatory impact analyses have still tended to focus on point estimates for $PM_{2.5}$ and ozone-related benefits. Frequently, the Agency has utilized more than one epidemiologic study to estimate mortality impacts because these estimates drive overall benefits for a given regulatory action due to the large monetary value assigned to such impacts. Risk estimates using the top epidemiologic studies sometimes differ by a factor of two or more. Presenting multiple estimates drawn directly from the primary literature is one way to convey the prevailing uncertainty. While this leads to an estimated range of benefits, it is not a range that reflects the true uncertainties in the underlying parameters supporting each study, either for mortality or for other effects. Because of the significant impacts of environmental regulations on the U.S. economy, it is essential that the Agency have confidence in the estimated benefits of an action, and their underlying uncertainties, prior to utilizing these estimates in a regulatory context.

A 2024 Scientific Advisory Board reviewed EPA's methods for estimating the health effects of $PM_{2.5}$ and clearly and repeatedly recommended that the EPA improve its approach to characterizing and presenting the uncertainty in estimating the health effects of $PM_{2.5}$.[51] A Tier 1 SAB recommendation was that the EPA present a single probabilistic mortality estimate based on pooled risk estimates with associated uncertainty ranges rather than present multiple estimates of mortality outcomes from the epidemiologic studies. The EPA was encouraged to explore meta-analysis methods or other forms of information synthesis, and support research and development of modified methods as needed.

[51] U.S. EPA. (2024). *Review of BenMAP and Benefits Methods*. (EPA/SAB/24/003). Washington DC: U.S. Environmental Protection Agency. Available at: https://sab.epa.gov/ords/sab/r/sab_apex/sab/advisoryactivitydetail?p18_id=2617&clear=18&session=15054897040198#report.

The OMB "2017 Report to Congress on the Benefits and Costs of Federal Regulations" listed six key assumptions underpinning $PM_{2.5}$ health effect estimation which introduce substantial uncertainties in the health effect estimates[52]:

1. That inhalation of fine particles is causally associated with premature death at concentrations near those experienced by most Americans on a daily basis;
2. That the concentration-response function for fine particles and premature mortality is approximately linear, even for concentrations below the levels established by the NAAQS;
3. That all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality;
4. That the forecasts for future emissions and associated air quality modeling accurately predict both the baseline (state of the world absent a rule) and the air quality impacts of the rule being analyzed;
5. That BPT approaches, when used to estimate benefits, are based on regional or national-level analysis that may not reflect local variability in population density, meteorology, exposure, baseline health incidence rates, or other local factors; and
6. That the estimated value of mortality risk reductions is an accurate reflection of what people would be willing to pay for incremental reductions in mortality risk from air pollution exposure, and that these values are constant across the life-cycle.

To the extent that any of these assumptions is incorrect, the benefit estimates will change, though the magnitude and direction of change are not known with certainty. The EPA is interested in improving understanding in each of these six areas. The EPA understands that additional research is needed, and will begin to develop approaches that reduce these

[52] See the OMB's "2017 Report to Congress on Benefits and Costs of Federal Regulations and Agency Compliance with the Unfunded Mandates Reform Act" for a fuller discussion on uncertainties. Available at https://trumpwhitehouse.archives.gov/wp-content/uploads/2019/12/2019-CATS-5885-REV_DOC-2017Cost_BenefitReport11_18_2019.docx.pdf.

uncertainties. The EPA will seek peer review for new methods developed from this work consistent with the OMB's Peer Review Guidance.[53]

In particular, the EPA is interested in reevaluating the validity of the approach for estimating the benefits of air quality improvements relative to the National Ambient Air Quality Standards (NAAQS) for $PM_{2.5}$ and ozone. These standards, which have been set at a level which the Administrator judges to be requisite to protect public health or welfare with an adequate margin of safety, are widely understood to represent the divide between clean air and air with an unacceptable level of pollution. Even in instances where an assumption is found to be justified based on scientific evidence, the EPA is interested in reevaluating its approach to characterizing and communicating underlying uncertainty to the public.

In the past, the EPA has explored a variety of approaches to shed light on how the estimated benefits of an action relate to the level of the NAAQS. For example, in estimating PM benefits, the Agency has employed techniques such as cutpoint analyses and Lowest Measured Level analyses, noting that we are most confident in the magnitude of the risks we project at $PM_{2.5}$ concentrations that coincide with the bulk of the observed $PM_{2.5}$ concentrations in the epidemiological studies that are used to estimate the benefits (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, Section 4.4.4, p. 4-26). However, such approaches address only a few of the sources of uncertainty that influence PM-related air quality benefits.

The limitations of reduced-form approaches, such as the BPT approach are even more pronounced than photochemical modeling/BenMAP-CE approaches due to: 1) the compounding effects of emissions reductions typically occurring across many geographic areas simultaneously, with varying proximity to population centers; 2) differing atmospheric transformation pathways for nitrous oxides (NOx), volatile organic compounds (VOCs), and secondary $PM_{2.5}$; and 3) region-specific photochemical and meteorological conditions. Using a national BPT estimate implicitly assumes uniform marginal health benefits for each ton of reduced emissions, an

[53] OMB (2005). *Memorandum M-05-03, Memorandum for the Heads of Executive Departments and Agencies: Issuance of OMB's Final Information Quality Bulletin for Peer Review*. Available at: https://www.federalregister.gov/documents/2005/01/14/05-769/final-information-quality-bulletin-for-peer-review.

assumption not supported given heterogeneity in exposure patterns and atmospheric chemistry. As more areas achieve or maintain attainment with the NAAQS, the uncertainties associated with low-concentration health effects grow, and marginal benefits become more difficult to characterize with precision.

Therefore, it may be appropriate for the EPA to separate exposures and impacts above the level of the standard from those occurring at lower ambient concentrations. The EPA will investigate this prior to estimating these impacts in a regulatory analysis even for informational purposes.

4.2.1 Air Quality Modeling Methodology and Results

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

As described in the Air Quality Modeling Appendix (Appendix A), gridded spatial fields of ozone and $PM_{2.5}$ concentrations representing the Baseline (with CPS) and the Final Repeal scenario were derived from CAMx source apportionment modeling in combination with NO_X, SO_2, and primary $PM_{2.5}$ EGU emissions obtained from the outputs of the IPM runs described in Section 3 of this RIA. The air quality modeling includes all inventoried pollution sources in the contiguous U.S. for the year 2022. Contributions from all sources other than EGUs are held constant at 2022 levels in this analysis, and the only changes quantified between the Baseline (with CPS) and Final Repeal scenario are those associated with the projected impacts of the final rule on EGU emissions. The EPA prepared gridded spatial fields of air quality for the Baseline (with CPS) and Final Repeal scenario for two 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.

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

The Air Quality Modeling Appendix also provides figures showing the geographical distribution of air quality changes in the Final Repeal scenario relative to the Baseline (with CPS). The spatial fields of Baseline AS-MO3 and annual average $PM_{2.5}$ and changes in the Final Repeal scenario relative to the Baseline (with CPS) in 2030, 2035, 2040 and 2045 are presented in Figure A-7 through Figure A-16. The spatial patterns shown in the figures are a result of (1) of the spatial distribution of EGU sources that are predicted to have changes in emissions and (2) of the physical or chemical processing that the model simulates in the atmosphere In later snapshot years (2035-2045) the air quality surfaces show broad areas of increased AS-MO3 and $PM_{2.5}$ across the eastern U.S. in the Final Repeal scenario versus the Baseline scenario (with CPS).

Figure A-17 through Figure A-26 show changes in AS-MO3 and $PM_{2.5}$ in 2030, 2035, 2040, and 2045 relative to recent 2022 conditions. Relative to recent 2022 conditions, these figures indicate that ozone and $PM_{2.5}$ concentration will decline in most locations for both Baseline (with CPS) and Final Repeal scenarios in each further out snapshot year. However, some areas of the country may experience slower rates of decline in ozone and $PM_{2.5}$ over time as a result of the predicted changes resulting from this Final Repeal.

4.2.2 NO_X-Related Health Effects

The Integrated Science Assessment for Oxides of Nitrogen – Health Criteria (NOX ISA) reviewed evidence from epidemiologic and laboratory studies on the health effects of exposure to NO_X, concluding that there is a likely causal relationship between respiratory health effects and short-term exposure to NO_2 (U.S. EPA, 2016). Epidemiologic and experimental studies encompassed several 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. NO_X emissions are also a precursor to ozone and fine particulate matter ($PM_{2.5}$) and may affect human health through these additional pathways.

4.2.3 SO_2-Related Health Effects

The Integrated Science Assessment (ISA) for Oxides of Sulfur – Health Criteria (SO_2 ISA) reviewed evidence from epidemiologic and laboratory studies on health effects of exposure to SO_2, concluding 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 the EPA's 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. SO_2 emissions are also a precursor to fine particulate matter ($PM_{2.5}$) and may affect human health through this additional pathway.

4.2.4 Ozone-Related Health Effects

Following a comprehensive review of toxicological, clinical, and epidemiological evidence, the ISA for Ozone and Related Photochemical Oxidants (Ozone ISA) (U.S. EPA, 2020c) found both short-term (i.e., less than one month) and long-term (i.e., one month or longer) ozone exposure to be related to an array of adverse human health effects. For each effect, the Ozone ISA reports relationships 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.

This assessment is based on the body of scientific evidence which can include observational human studies, experimental human exposure studies, animal model studies, and mechanistic studies.

The Ozone ISA found short-term exposure to ozone to be causally related to respiratory effects, including respiratory mortality, and likely to be causally related to metabolic effects. For short-term exposure, evidence was suggestive of a causal relationship for cardiovascular and nervous system effects as well as total mortality. The Ozone ISA reported that long-term exposure to ozone is likely-to-be-causally related to respiratory effects, including respiratory mortality. Evidence on metabolic, cardiovascular, reproductive, and nervous system effects as well as total mortality was suggestive of a causal relationship with long-term ozone exposure.

When adequate data and resources are available, the EPA has generally quantified health effects which the Ozone ISA classified as causally related or likely-to-be-causally related to short- or long-term ozone exposure. Health effects classified as suggestive-of-causality or weaker have not historically been quantified. Historically quantified health effects include premature respiratory mortality, hospital admissions and emergency department visits, asthma onset and related symptoms (chest tightness, cough, shortness of breath, and wheeze), allergic rhinitis symptoms, as well as restricted activity days and school absences. The EPA did not quantify or monetize the benefits or disbenefits associated with changes in the incidence of the listed health effects for this rule.

4.2.5 $PM_{2.5}$-Related Health Effects

$PM_{2.5}$ describes an array of pollutants from human and natural sources with diameters that are generally 2.5 micrometers and smaller. This includes directly emitted $PM_{2.5}$ as well as $PM_{2.5}$ formed through atmospheric chemical reactions of precursor pollutants including NO_X and SO_2.

Following a comprehensive review of toxicological, clinical, and epidemiological evidence, the Integrated Science Assessment for Particulate Matter (PM ISA) (U.S. EPA, 2019a) and the Supplement to the Integrated Science Assessment for Particulate Matter (PM ISA Supplement) (U.S. EPA, 2022a) found $PM_{2.5}$ to be related to an array of adverse human health effects. For each effect, the PM ISA and PM ISA Supplement report relationships 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. This assessment is based on the body of scientific evidence which can include observational human studies, experimental human exposure studies, animal model studies, and mechanistic studies.

The PM ISA and PM ISA Supplement found acute and chronic exposures to $PM_{2.5}$ to be causally related to cardiovascular effects and total mortality (i.e., premature death), and respiratory effects as likely-to-be-causally related. Chronic exposures to $PM_{2.5}$ were also determined to be likely-to-be-causally related to nervous system effects and cancer, with the latter determination based primarily on evidence from studies of lung cancer incidence as well as decades of research on the mutagenicity and carcinogenicity of PM. Evidence was suggestive of a causal relationship for reproductive and developmental effects, pregnancy and birth outcomes, and metabolic effects.

When adequate data and resources are available, the EPA has generally quantified health effects which the PM ISA and PM ISA Supplement classified as causally related or likely-to-be-causally related to $PM_{2.5}$ exposure. Health effects classified as suggestive-of-causality or weaker have not historically been quantified. Historically quantified health effects include premature respiratory mortality, heart attacks, cardiovascular hospital admissions, cardiovascular emergency department visits, respiratory hospital admissions, respiratory emergency room visits, cardiac arrest, stroke, asthma onset, asthma symptoms/exacerbation, lung cancer, allergic rhinitis (hay fever) symptoms, lost workdays, and minor restricted-activity days. The EPA did not quantify or monetize the benefits or disbenefits associated with changes in the incidence of the listed health effects for this rule.

4.2.6 Welfare Effects

The economic justification for regulatory actions targeting reductions in emissions of air pollutants generally follows that the regulation mandates the subject of such actions to internalize unpriced social costs, or "negative externalities." Cost analyses therefore explore the magnitude and incidence of compliance costs, such as by capital investment borne by producers or via increased market prices, while benefits analyses provide reference points for determining whether a regulation is efficient to the extent that it results in greater benefits from improved air quality than the costs that society must pay. Due to operational constraints and data limitations, most benefits analyses focus on human health effects expected to occur because of changes in primary and secondary pollutant concentrations resulting from the rulemaking; however, the benefits of reductions in emissions of air pollutants include additional effects that, unlike costs, extend beyond direct impacts to economic interests.

The Clean Air Act encourages consideration of the welfare effects of air pollutants, which it defines as including, but not limited to, effects on soils, water, crops, vegetation, manmade materials, animals, wildlife, weather, visibility, and climate, damage to and deterioration of property, and hazards to transportation, as well as effects on economic values and on personal comfort and well-being, whether caused by transformation, conversion, or combination with other pollutants (42 U.S.C. §7602(h)). In this section, we provide qualitative discussions of select welfare effects.

4.2.6.1 Ozone Effects: Vegetation and Ecosystem Effects

Exposure to ozone has been found to be 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 66 vegetation species identified as "ozone-sensitive," many of which occur in state and national parks and forests. These effects include those that cause damage to, or impairment of, the intended use of the plant or ecosystem. Such effects are considered adverse to public welfare and can include reduced growth and/or biomass production in sensitive trees, reduced yield and quality of crops, visible foliar injury, changes to species composition, and changes in ecosystems and associated ecosystem services (U.S. EPA, 2020c).

4.2.6.2 Ozone Effects: Animal Welfare Effects

While effects can be context- and species-specific, a large body of scientific evidence links ozone exposure to health effects in animals. When exploring environmental pathways through which environmental effects of ozone may impact animals, the Ozone ISA found a likely-to-be-causal relationship between ambient ozone concentrations and alterations of herbivore growth and reproduction (U.S. EPA, 2020c, Girón-Calva et al. 2016, Habeck and Lindroth, 2013, Hong et al., 2016, Ueno et al., 2016). In addition, many animal toxicological studies served as evidence for determining the causality of relationships between human exposure to ozone and human health effects, including respiratory and metabolic effects. The

Ozone ISA states, “A large body of experimental animal toxicological studies demonstrates (short- and long-term) ozone-induced changes in measures of lung function, inflammation, increased airway responsiveness, and impaired lung host defense” (U.S. EPA, 2020c). Additionally, animal studies report relationships between short-term ozone exposure and metabolic effects in various stocks and strains of animals across multiple laboratories (U.S. EPA, 2020c, Gordon et al., 2017, Miller et al., 2015, Ying et al., 2016,).

4.2.6.3 $PM_{2.5}$ Effects: Visibility Effects

Reducing secondary formation of $PM_{2.5}$ would improve levels of visibility in the U.S. because suspended particles and gases degrade visibility by scattering and absorbing light (U.S. EPA, 2019). Fine particles with significant light-extinction efficiencies include sulfates, nitrates, organic carbon, elemental carbon, and soil. 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. Previous analyses such as U.S. EPA (2012) show that visibility benefits can be a significant welfare benefit category.

4.2.6.4 $PM_{2.5}$ Effects: Animal Welfare Effects

While effects can be context- and species-specific, a large body of scientific evidence links $PM_{2.5}$ exposure to health effects in animals. The PM ISA and PM ISA Supplement evaluated relationships exposures to $PM_{2.5}$ and an array of health markers described in animal toxicological studies. Animal toxicological studies have found evidence that $PM_{2.5}$ induces changes in measurements including but not limited to breathing patterns (Diaz et al., 2013), airway irritation (Nikolov et al., 2008), impaired heart function (Kurhanewicz et al., 2014), changes in blood pressure (Wagner et a., 2014), oxidative stress (Ghelfi et al., 2010, Davel et al., 2012), reproductive outcomes (Pires et al., 2011, Veras et al. 2012, de Melo et al., 2015), and other outcomes (U.S. EPA, 2019; U.S. EPA, 2022a). However, neither the PM ISA nor the PM ISA Supplement provide a causality determination of the causality of $PM_{2.5}$ affecting animal health endpoints (U.S. EPA, 2019; U.S. EPA, 2022a).

4.3 Additional Unquantified Benefits

4.3.1 Hazardous Air Pollutant Impacts

The rule is expected to increase fossil-fired EGU generation and consequentially is expected to lead to increased HAP emissions. HAP emissions from EGUs create risks of premature mortality from heart attacks, cancer, and neurodevelopmental delays in children, and detrimentally affect economically vital ecosystems used for recreational and commercial purposes. Further, these public health effects are particularly pronounced for certain segments of the American population that are especially vulnerable (e.g., subsistence fishers and their children) to impacts from EGU HAP emissions.

4.3.1.1 Mercury Air Pollutant impacts

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

4.3.1.2 Metal HAP

The projected increases in emissions of non-mercury metal HAP are expected to increase 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). 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.

4.3.2 Water Quality and Availability Benefits

At coal units that increase generation, there are several negative health, ecological, and productivity effects associated with water effluent and intake. 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. The potential disbenefits come in the form of increased morbidity, mortality, and on environmental quality and economic activities; increases in water use; and increases in the use of surface impoundments to manage Coal Combustion Residual wastes, with additional 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 disbenefits from surface water quality deterioration may include drinking water impacts and fish consumption impacts.

In addition, corresponding surface water quality changes can affect the ecological condition and recreation use effects. The EPA expects the ecological impacts from increased 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.

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5 SOCIAL COSTS AND ECONOMIC IMPACTS

This section discusses potential energy market impacts, economy-wide social costs and economic impacts, and small entity impacts associated with this action. The social cost and economy-wide impacts are estimated using EPA's SAGE model. Note that SAGE does not currently estimate changes in emissions nor account for environmental impacts resulting from this action. 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 (the change in retail electricity prices reported here is a national average across residential, commercial, and industrial consumers), natural gas, and coal resulting from this action. Table 5-1 summarizes the impact of these potential changes on other markets. We refer to these changes as secondary market impacts.

Table 5-1 Summary of Certain Energy Market Impacts

	2030	2035	2040	2045
Retail electricity prices	0.7%	-5.8%	-1.1%	-2.6%
Average price of coal delivered to the power sector	4.3%	10.5%	10.0%	27.3%
Coal production for power sector use	4%	47%	57%	1405%
Price of natural gas delivered to power sector	-2.2%	-8.5%	0.6%	-1.9%
Price of average Henry Hub (spot)	-2.2%	-8.2%	0.7%	-1.9%
Natural gas use for electricity generation	-1.6%	-8.9%	1.9%	-3.1%

5.2 Economy-wide Social Costs and Economic Impacts

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

5.2.1 Economy-wide Modelling

In 2015, the 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 are most informative when there are both significant cross-price effects and pre-existing distortions in those markets (U.S. EPA Science Advisory Board, 2017).[54] 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 the 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 (e.g., monetized health effects) of the regulation are not incorporated into the models, though it highlighted explicit treatment of benefits within a CGE framework as a long-term research priority. In addition, the panel observed that CGE models may also offer insights into the ways costs are distributed across regions, sectors, or households.

In response, the 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 (SAGE is an Applied General Equilibrium). The SAGE model can provide an important complement to the analyses typically performed during regulatory development by evaluating a broader set of economic impacts and offering an economy-wide estimate of social costs.[55] For

[54] 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).
[55] CGE models may also be able to provide additional information on the benefits of regulatory interventions, though this is a relatively new but active area of research. Note that until the benefits that accrue to society from mitigating environmental externalities can be incorporated in a CGE model, the economic welfare measure from the CGE model is incomplete and needs to be augmented with traditional benefits analysis to develop measures of net benefits.

this analysis, we use version 2.1.1 of EPA's SAGE model (Marten et al., 2024). As discussed in EPA's *Guidelines for Preparing Economic Analyses*, social costs are the total economic burden of a regulatory action (U.S. EPA, 2024). 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.

5.2.2 Overview of the SAGE CGE Model

SAGE is a CGE model that provides a complete, but relatively aggregated, representation of the entire U.S. economy. CGE models assume that for some discrete period of time an economy can be characterized by a set of conditions in which supply equals demand in all markets (referred to as equilibrium). When the imposition of a regulation alters conditions in one or more markets, the CGE model estimates a new set of relative prices and quantities for all markets that return the economy to a new equilibrium.[56] 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., 2024). 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 equilibrium (i.e., the baseline).

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. The SAGE model includes explicit subnational regional representation within the U.S. at the Census Region level. Each region contains a representative firm 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

[56] 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 that restrict its ability to adjust instantaneously (e.g., rigidities in capital markets and frictions in labor markets).

representative households that vary by income level and have region-specific preferences. Within the economy, households and firms are assumed to interact in perfectly competitive markets. In addition to households and firms, there is a single government in SAGE that represents all state, local and federal governments within the U.S. The government imposes taxes on capital earnings, labor earnings, and production and uses that revenue (in addition to deficit spending) to provide government services, make transfer payments to households, and pay interest on government debt. Table 5-2 summarizes the dimensions of the SAGE model.

Table 5-2 SAGE Dimensional Details

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

To capture domestic and international trade the model's structure accounts for the possibility that the U.S. can be both an importer and an exporter of the same good. SAGE addresses this possibility 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 U.S. is a large, open economy).

SAGE is a forward-looking intertemporal model, which means that the model assumes households and firms take into account what is expected to occur in future years and how current decisions will impact those outcomes when making their decisions. 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 distinguishing 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 in that it can only be used for its original purpose unless a relatively high cost is incurred to alter its functionality. New capital is more flexible and can be adjusted 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 any region of the country.

The dynamics of the baseline economy in SAGE are informed through the calibration of key exogenous parameters in the model, including 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.[57] 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.[58] These data are combined with key behavioral parameters for firms and households that are adopted 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, the EPA initiated a separate SAB panel to conduct a technical review of SAGE (U.S. EPA Science Advisory Board, 2020). Peer review of SAGE was in accordance with requirements in OMB guidelines (OMB, 2004) for influential scientific documents. 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 the EPA to incorporate before using the model in regulatory analysis (denoted as Tier 1 recommendations by the SAB). The SAB's Tier 1 recommendations, including improving the calibration of government expenditures and deficits and the foreign trade deficit; allowing for more flexibility in the consumer demand system; and representing the United States as a large open economy, are incorporated into the model version used in this analysis (v2.1.1), as are several of the SAB's other medium- and long-run recommendations. For more details on the SAGE model, complete documentation, source code and build stream are available on EPA's website.[59]

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[57] The IMPLAN data is a constructed dataset based on several publicly available sources of information including the Bureau of Economic Analysis' Use and Supply tables, the National Income and Product Accounts, and several others. While the underlying IMPLAN data are proprietary, the 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).

[58] 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.

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

5.2.3 Linking IPM Partial Equilibrium Model to SAGE CGE Model

The SAB noted that electricity sector regulations are a suitable candidate for economy-wide modeling because of the many 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. For this analysis, the EPA has relied on the IPM, a partial equilibrium large-scale linear programming model, to assess the costs of compliance in the power sector and related energy markets (see Section 3.3 for more details on the use of IPM).

The following subsections explain the methodology for linking SAGE and IPM, particularly the details relevant to the specific context of this finalized repeal. For example, SAGE does not include an explicit representation of recent legislation, such as the Inflation Reduction Act of 2022 (IRA) and the One Big Beautiful Bill Act of 2025 (OBBBA). Therefore, the model linkage methodology accounts for tax and subsidy payments from investment and production tax credits (i.e., 45Y, 48E and 45Q) that are not represented in the default tax and subsidy structure in the model. Schreiber et al. (2023) and Schreiber et al. (2025) include a detailed description of how the models are linked.

5.2.3.1 Compliance Costs and Social Costs

As described in Section 3.3, for the baseline and final repeal scenario, IPM solves for the least-cost approach to meet fixed electricity demand based on highly detailed information about electricity generation, air pollution control technologies, and primary energy market conditions (coal and natural gas) while satisfying regulatory requirements, resource adequacy, and other constraints in the electricity sector. Potential effects outside of the electricity, coal, and natural gas sectors are not evaluated within IPM. Electricity demand is fixed such that the quantity demanded is unchanged between the baseline and policy case. IPM estimates changes in compliance costs as the changes in expenditures by the power sector to achieve and maintain compliance with the current rules in the baseline relative to a policy case with certain rules removed or included.

Specifically, IPM minimizes system cost, which is the sum of the total amortized payments to electricity-generating, pollution control, and transmission investments, delivered fuel costs, total variable and fixed operating and maintenance (O&M) costs, and expenditures on pollution transportation and storage, subject to regulatory and other constraints:[60]

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

Note that system costs include transfers. For example, amortized payments to capital are inclusive of corporate, state, and local taxes, investment tax credits, and interest payments. Similarly, expenditures on pollution transport and storage account for the value of 45Q tax credits.[61] This allows IPM to account for transfers, including taxes and subsidies (e.g., IRA and OBBBA tax credits) that may target specific technologies and influence their adoption when modeling generation and investment decisions.[62]

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

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

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

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

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[60] For further details on IPM's objective function and model formulation, see Chapter 2, and in particular Section 2.2, of the IPM documentation (available at https://www.epa.gov/power-sector-modeling). IPM's objective function also accounts for energy and capacity payments for transmission, which accounts for the cost of constructing new transmission. Projected changes in capital expenditures on transmission from IPM are also accounted for in the SAGE analysis.

[61] Specifically, pollution transportation and storage costs include costs for transporting captured CO2 to injection sites and storing it at these sites net of tax credits for carbon storage (i.e., 45Q) and revenues earned from selling CO2 for enhanced oil recovery (EOR) (Chapter 6, IPM documentation, available at https://www.epa.gov/power-sector-modeling). While revenues from EOR are not explicitly represented in the expressions here, the approach to linking IPM results to SAGE accounts for the value of the change in CO2 provided for EOR between the baseline and policy scenarios.

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

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

The estimated compliance costs from IPM differ from the social costs of this repeal for several reasons. First, the estimated compliance costs from IPM include changes beyond real resources costs, specifically transfers that should be excluded from an estimate of social costs. Second, the compliance cost estimates from IPM do not account for all relevant margins of substitution that the economy may use to respond to the final repeal (e.g., quantity of electricity demanded).[63] Third, the compliance cost estimates from IPM do not account for the possibility of significant cross-price effects and interactions with other pre-existing market distortions elsewhere in the economy. Fourth, the compliance cost estimates from IPM do not account for reallocation across sectors, potential changes in aggregate investment, or the resulting effects on economic growth. By construction, SAGE explicitly allows for these possible responses and is therefore used to estimate social costs, while leveraging the insights that the detailed IPM provides on changes in compliance behavior and costs to the power sector from this final repeal.[64]

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

[64] The last three of these reasons for why the compliance and social cost estimates differ are also reasons why the real resource and social cost estimates differ.

5.2.3.2 Overview of the Linking Methodology

To model the economy-wide effects of the final repeal, we calibrate the SAGE model inputs that represent the impact of the final repeal. SAGE model inputs are calibrated such that sectoral costs in a corresponding partial equilibrium sub-model of SAGE (called SAGE-PE) align with the compliance costs (excluding transfers) derived from the technology-rich IPM. We then pass the calibrated inputs from SAGE-PE to the full SAGE model to obtain the full general equilibrium effects of the rule. This approach of aligning compliance costs between the two models allows us to avoid confounding the estimate of economy-wide effects with differences in the models' representations of sectors shared by both IPM and SAGE.[65] Care is given in translating IPM outputs for use in SAGE so that the two models adequately capture equivalent compliance costs.

Figure 5-1 provides an overview of the approach leveraging the IPM results to introduce the incremental changes in costs from the final repeal into the SAGE model. In the first step (characterized as Step 0), model differences in structure and accounting are reconciled by translating IPM incremental system costs to a format consistent with the SAGE framework. This includes aligning model years, distributing IPM costs to SAGE model inputs (by fuel, other materials, labor, and capital), attributing costs to production vintages, and removing transfer payments that may be important for IPM to capture investment behavior but inappropriate for inputs into SAGE as they would result in double counting.

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

[65] 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."

electricity, coal mining and natural gas sectors, electricity demand, factor prices, and constraints on factor supply are all treated as exogenous in SAGE-PE.

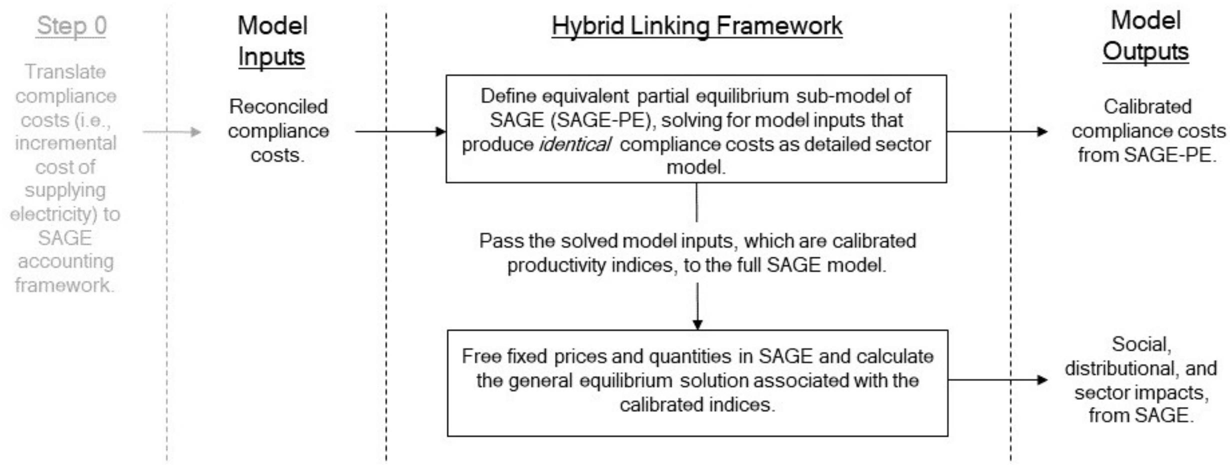

Figure 5-1 Hybrid Linkage Approach for IPM and SAGE

Because SAGE-PE is a sub-model of SAGE, most of its model equations are described in Marten et al. (2024). 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 maintains 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., 2024). 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.[66]

To align SAGE with IPM, the productivity shock is calibrated so that the compliance costs are aligned between SAGE-PE and the IPM solution.[67] The incremental SAGE-PE costs are defined as the difference in production costs between the policy equilibrium and the baseline. The productivity shock is adjusted to equate SAGE-PE and IPM incremental costs. Because prices for factors and non-energy inputs are not endogenously determined in SAGE-PE the incremental input costs for factors and non-energy inputs are driven through quantity demand changes for labor, new capital, and material inputs. Incremental costs for electricity, coal mining and natural gas inputs incorporate both changes in prices as well as input demand quantities. Electricity production in SAGE-PE is exogenous except for adjustments necessary to satisfy reductions or increases in electricity input demands in the electricity sector and primary energy sectors in response to the final repeal. 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) and Schreiber et al. (2025) for more details on the linking approach. In addition to the calibrated productivity parameters in the electricity sector, we separately represent changes in revenues from selling CO_2 for enhanced oil recovery from the final repeal as a Hicks-Neutral productivity shock in the crude oil extraction sector to account for the impact of changes in captured CO_2 being used in the production of crude oil as a result of the policy.

5.2.3.3 Translating IPM Outputs into SAGE Inputs

IPM produces detailed cost and emissions outputs by model plant, which are aggregate representations of unit-level information of existing generators or characterizations of new

[66] The SAGE model was modified to allow production with extant capital to require incremental new capital for compliance (e.g., pollution control retrofits, fuel switching). This modification is implemented by defining an additional productivity index associated with new capital demands in production with extant capital.
[67] The calibrated compliance costs, per Figure 5-1, can be calculated using code and data available in the docket.

generators, and wholesale electricity price impacts by IPM region.[68] This detailed information is important for quantifying the sectoral compliance behavior attributed to a regulatory shock. However, to link IPM and SAGE to capture the broader economy-wide impacts, IPM costs need to be translated to SAGE factors and commodities. Table 5-2 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 amortized capital payments. Overnight capital costs reflect the total value of the resources used to install a piece of capital "overnight," or without any financing costs associated with loan repayment. In reality, these expenditures are not paid immediately but rather spread out over a fixed time period with interest via amortized capital payments. The "cost" of capital in IPM is a combination of a rate of return, tax payments, and financing charges (embodied in the CRF) and is used to amortize payments over the lifetime of the capital investment. Costs are further denominated by IPM region, fuel type, and generator vintage.

Table 5-3 IPM Cost Outputs

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

IPM incremental costs are translated into the SAGE framework by: (1) mapping IPM model years to SAGE model years;[69] (2) mapping IPM regions to SAGE regions; (3) splitting delivered fuel costs to separate transportation costs; (4) attributing a portion of total operations

[68] The reduced MR&R costs of the final repeal are also accounted for when translating compliance cost outputs into SAGE inputs. The reduced MR&R costs are treated as a reduction in expenditures on labor by state governments in the translation.
[69] Because SAGE has a longer time horizon than IPM (to 2081), IPM incremental costs in 2055 are assumed to extend to 2059 and then fall to zero for the remainder of the model horizon. Since SAGE and IPM have different representative model years, we must also establish a mapping between IPM model years, SAGE model years, and calendar years. We have improved this methodology since proposal to ensure that the resource requirements used to calibrate the SAGE policy run preserve the present value of the real resource cost estimates projected in IPM.

and maintenance costs to labor;[70] (5) mapping the remainder of total operations and maintenance costs to specific inputs in SAGE according to the reference cost structure in the model; (6) attributing incremental costs on existing and new generation to production with extant and new capital, respectively;[71] and (7) removing taxes and other transfers from capital payments using the difference between the capital charge rate and the CRF to recover the real resource costs associated with capital.

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 in the power sector with technology specific rates of depreciation. The models can be aligned by either targeting incremental overnight capital costs (e.g., the magnitude and timing of the resource change) or through targeting amortized capital payments. Because the accounting for capital is different between models, the former approach can lead to significant differences in capital payments between models. Therefore, the second approach is used to align incremental amortized payments to capital that exclude tax payments when calibrating the productivity shock. Because the representation of capital is different between the models, differences in induced investment in the capital stock from targeting consistent amortized payments can be thought of as a translation of payments (e.g., a means to translate a fixed term investment into a cumulatively depreciated asset).

[70] Using information on existing capacity and generation from the Energy Information Administration, costs of operations and maintenance per unit of electricity from IPM, and employee compensation from the Quarterly Census for Employment and Wages produced by the Bureau of Labor Statistics, we find an average labor share of total operations and maintenance of 0.3 in the electricity sector.

[71] Production with extant and new capital is not equivalent to differentiating existing and new generation in the IPM modeling framework. For example, the lifespan of existing generators in IPM can be extended through investments in ways that are not directly comparable to production with extant capital in the SAGE model. In this analysis, we therefore apportion the impacts on existing generators from IPM to extant production and new production in SAGE based on the depreciation rate of 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. Therefore, it is possible that the linked framework may over- or under-attribute incremental costs to less flexible production processes in SAGE.

Because SAGE does not explicitly represent investment and production tax credits that affect power sector investment, specifically the 45Y, 48E and 45Q credits, the model linkage methodology is adjusted to account for changes in the total value of these subsidies as a result of the regulation. The SAGE-PE model is calibrated to match both the real resource requirements for the expected compliance pathway and the impact of these subsidies on the compliance expenditure for the electricity sector. To accomplish this, the change in real resource requirements paid for by these subsidies are included in the incremental costs of the final repeal as described above (i.e., the incremental costs exclude subsidy payments).[72] To avoid overstating electricity price impacts and the associated social cost from changes in electricity prices, the net tax rate on electricity sector production is also adjusted within the calibration of the SAGE-PE model to reflect the expected change in these subsidy payments as a result of the policy. 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 45Y, 48E and 45Q tax credits and changes in revenues from other taxes (e.g., output, capital, and labor) as the economy adjusts in response to the final repeal.

5.2.4 Modeling Updates Since Proposal

The EPA has incorporated several improvements into this economy-wide analysis relative to the proposal RIA:

- Social costs are expressed in terms of changes in real full consumption in Section 5.2.3.1.
- The methodology for mapping IPM model years to SAGE model years has been updated. The two models use different time steps which requires a method to map between the model years. The improved method ensures that the resources requirements used to

[72] 45Y and 48E tax credits are levied on capital whereas the 45Q tax credit is shared across inputs according to an assumed cost structure for carbon capture and storage based on a combination of both the natural gas extraction sector in the SAGE model and the cost structure of pipeline transportation from the Bureau of Economic Analysis. The adopted approach for modeling the costs of carbon capture and storage approximately align with information found in Ortiz et al. (2013) and McFarland and Herzog (2006).

calibrate the SAGE policy run preserve the present value of the real resource compliance cost estimates projected in IPM.

- The present and annualized values of cost estimates presented in this chapter of the RIA are now based on the SAGE model's endogenous consumption discount rate path. In the proposal RIA, the present and annualized values in this chapter used a constant discount rate consistent with the average discount rate over the first 20 years of the model's time horizon. Explicit use of the model's endogenous consumption discount rate provides better alignment between the present and annualized cost estimates and the underlying modeling.
- Consistent with previous sections of this RIA that report real resource cost estimates presented in Table 3-7 in Section 3.4.3, SAGE model inputs have been updated to reflect more recent and resolved information on transfers related to capital investments and enhanced oil recovery.

5.2.5 Results

This section summarizes the estimated economy-wide impacts of the final repeal. SAGE model results include aggregate social costs, macroeconomic impacts, sectoral impacts, and distributional impacts. Note that SAGE does not currently estimate changes in emissions nor accounts for the effects of changes in environmental quality on the economy.

5.2.5.1 Economy-wide Social Costs

Table 5-4 presents the economy-wide, general equilibrium social costs of the final repeal, calculated as the change in real full consumption from the final repeal relative to the baseline. Real full consumption measures the value of the consumption of goods, services, and leisure measured in baseline prices. This differs from the social cost metric presented in the proposal RIA, which relied on equivalent variation.[73] Equivalent variation by definition does not provide detail on how the social costs of a regulation are borne over time in an intertemporal framework limiting our ability to calculate meaningful social cost estimates for a period of time that is a

[73] Equivalent variation is a theoretically appropriate measure of social cost (U.S. EPA Science Advisory Board, 2017). Equivalent variation is an estimate of the amount of money that society would be willing to pay to avoid the compliance requirements of the final repeal, setting aside health, climate, and other benefits (quantified or described qualitatively elsewhere in the RIA).

subset of the SAGE model time horizon comparable with the IPM results presented in Section 3.3.[74] The present value of changes in real full consumption closely approximates the present value of equivalent variation across the full model time horizon but better communicates the temporal impacts of a regulation (e.g., when compliance investments occur).[75]

Table 5-4 also presents the real resource compliance costs estimated by IPM – which exclude all transfer payments – mapped to SAGE model years. Compliance costs are presented as they are input into SAGE. For both the compliance costs and the general equilibrium social costs, Table 5-4 presents the present value and annualized costs using the consumption discount rate endogenous to the SAGE model.[76] The consumption discount rate in the model, which is the internally consistent rate to discount modeled changes in full consumption, is based on calibrated household preferences and baseline growth and averages approximately 4 percent over the model's time horizon. The model is calibrated such that social rate of return to capital in the model is approximately 7 percent, conditional on the effective marginal capital tax rate.

The annualized social cost estimated in SAGE for the final repeal is approximately -$23 billion (2024 dollars) between 2026 and 2047 based on the value of changes in real full consumption and using the internal consumption discount rate in the model.[77] The temporal pattern of social costs reflects a reallocation of consumption and investment in response to the compliance requirements of the final repeal. Cost savings are highest in earlier model years due

[74] See Section 4.2 in Marten et al., (2024) for additional details for how equivalent variation is allocated over time in SAGE.

[75] Changes in real consumption has been used to approximate social costs in CGE models, for example with alternative expectations that constrain the intertemporal utility maximization problem (McKibbin and Wilcoxen, 1999).

[76] The SAGE model estimates the present value of costs for each representative household in the model and sums those estimates to calculate the present value of social costs. Implicit in those estimates are endogenous discount rates that vary by household and over time. See Section 3.4 of the SAGE model documentation at https://www.epa.gov/environmental-economics/cge-modeling-regulatory-analysis.

[77] Changes in real full consumption provides a good approximation to equivalent variation, while providing additional detail on the temporal pattern of when impacts are expected to be experienced. Across the full model time horizon, the estimated value of equivalent variation is within 1.5 percent of the value of the change in real full consumption.

to reductions in needed investments in anticipation of reductions in capital requirements in the electricity sector.[78]

Table 5-4 Real Resource Costs and Social Costs (billion 2024 dollars)

SAGE Model Year	Real Resource Costs - Input to SAGE (Excluding Transfers)	General Equilibrium Social Costs
2026	1.0	-24
2031	-29	-25
2036	-29	-23
2041	-18	-19
2046	-11	-16
2051	-6.9	-13
Present Value (2026 to 2047)	-230	-310
Equivalent Annualized Value (2026 to 2047)	-17	-23

Notes: Social costs are calculated as changes in real full consumption. Present value and annualized cost estimates are calculated by interpolating costs estimates between SAGE model years and discounted using the internal consumption discount rate in the model. IPM outputs are mapped to SAGE model years to preserve the present value of real resource compliance costs and therefore will differ from Table 3-7 in Section 3.4.3.

This social cost estimate reflects the combined effects of real resource use from the final repeal and interactions with tax credits for specific production technologies and CCS that are expected to see decreased use in response to the final repeal. We are currently not able to identify their relative roles.

5.2.5.2 Macroeconomic Impacts

The estimated percent change in real gross domestic product (GDP), or the real value of the goods and services produced by the U.S. economy, and its components are presented in Figure 5-2. 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) +

[78] To be consistent with IPM modeling results, SAGE results assume that IPM costs extend to 2059 and then are zero to the end of the SAGE model horizon. Treatment of these outyears is a point of uncertainty in modeling the economy-wide impacts in an intertemporal model. Due to discounting, plausible treatment of these outyears likely has a relatively small effect on social costs between 2026 and 2047. However, SAGE's foresighted behavior allows the model to reallocate investment and consumption over time, which can produce differences in results. For example, extending the 2055 results from IPM to the terminal year in the SAGE model leads to an increase (in absolute value) in the present value of social costs by 2.7 percent between 2026 and 2047.

Government (G) + (Exports (X) – Imports (M)). The final repeal is estimated to increase real GDP across most of the model time horizon, with a peak increase of 0.09 percent in 2036.[79]

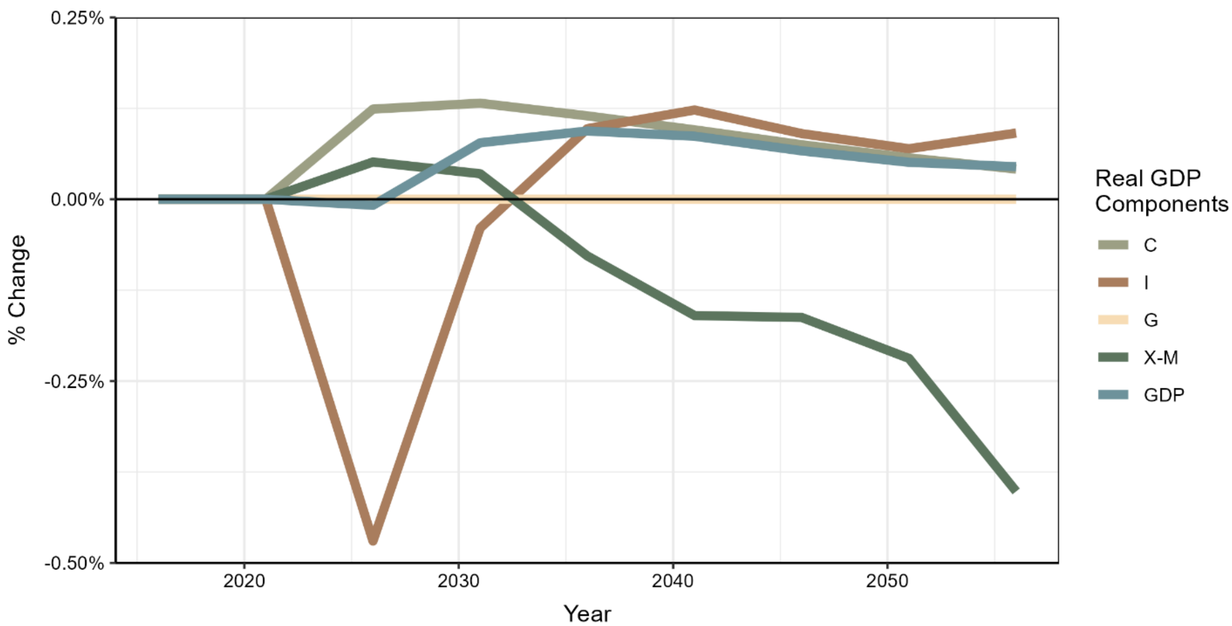

Figure 5-2 Percent Change in Real GDP and Components

Figure 5-2 also reports changes in the components of GDP from the expenditure side of the economy. The final repeal is expected to decrease investments in the electricity sector, leading to a reduction in aggregate investment in 2026 and 2031 (0.47 percent and 0.04 percent, respectively). A reduction in investment reallocates resources toward consumption and as a result, the final repeal increases consumption throughout the model time horizon. Aggregate investment is expected to then increase in later model years. The final repeal is also expected to impact the net trade balance, including a modest increase in net exports in the initial years through changes in domestic relative prices due to avoided compliance, and reductions thereafter from increases in imports to accommodate increases in aggregate consumption and investment.

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[79] 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). U.S. EPA Science Advisory Board (2017) notes: "GE models are strongly grounded in economic theory, which allows social costs to be evaluated using equivalent variation or other economically rigorous approaches. Simpler measures, such as changes in gross domestic product or in household consumption, do not measure welfare accurately and are inappropriate for evaluating social costs." Social cost estimates presented in Table 5-4 rely on measures of full consumption, which captures impacts on leisure.

5.2.5.3 Sectoral Impacts

Figure 5-3 presents the estimated percent change in output and real output prices for each sector in model years 2026, 2031, 2036, and 2041.[80] Changes in output reflect the estimated shifts in inputs used by generation sources in addition to an economy-wide demand response to changes in electricity prices or changes to enhanced oil recovery revenues. Similarly, the estimated changes in sector output prices reflect compliance cost reductions associated with the final repeal, demand side changes in electricity use from both firms and households, as well as the use of 45Y, 48E and 45Q tax credits. Electricity sector prices are expected to decrease after 2026. As the price of electricity falls, the economy is expected to increase demand for electricity through a variety of pathways. Measured in terms of percent change from the baseline, output and price changes in the electricity, coal mining, natural gas, and crude oil sectors are expected to be relatively larger than in other sectors of the economy. Modest output increases 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 decreases in sectors associated with capital formation in 2026 and 2031 due to reductions in investments attributable to the final repeal. Output price changes in non-energy sectors are expected to be relatively small.

[80] CGE models report prices in relative terms. We denominate output prices in terms of a 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 this CPI allows a comparison of changes in the magnitude of output prices to overall trends in the economy (i.e., a percentage change that is positive reflects a price that increases more than the average price changes across the economy).

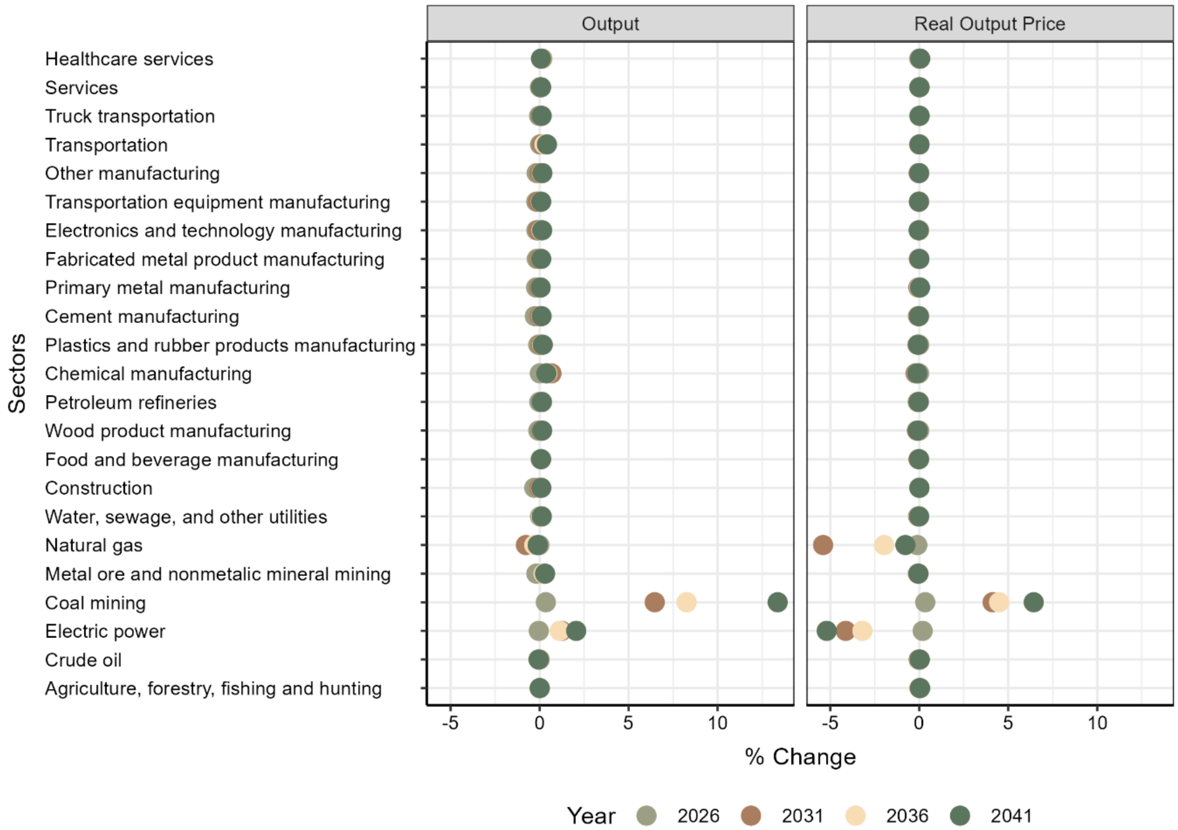

Figure 5-3 Percent Change in Sectoral Output and Real Output Prices

5.2.5.4 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. Consumer prices, averaged across all end-use household demands and measured relative to the wage rate are expected to decrease by up to 0.18 percent in 2041. The SAGE model characterizes representative households by income quintiles in each of the four Census regions. This allows the change in the present value of real full consumption over the SAGE forecast horizon to be separately estimated across the income distribution and for different regions of the country, as presented in Figure 5-6.[81] Changes in real full consumption are generally expected to increase with income with the

[81] The distribution of changes in real full consumption is calculated for the period 2026 to 2047 and divided by the total number of households of a given income quintile and region in the model's benchmark year using estimates from the Census' Current Population Survey. While we report the present value of the change in real full consumption in Figure 5-6, distributional results can also be annualized or calculated as a percentage of baseline full consumption using code and data in the docket.

exception of the top income quintile, which derives a larger share of income from capital ownership. Estimates in Table 5-6 reflect a combined effect of the final repeal on resource requirements and interactions with 45Y, 48E and 45Q tax credits that are expected to see decreased use in response to the final repeal.[82]

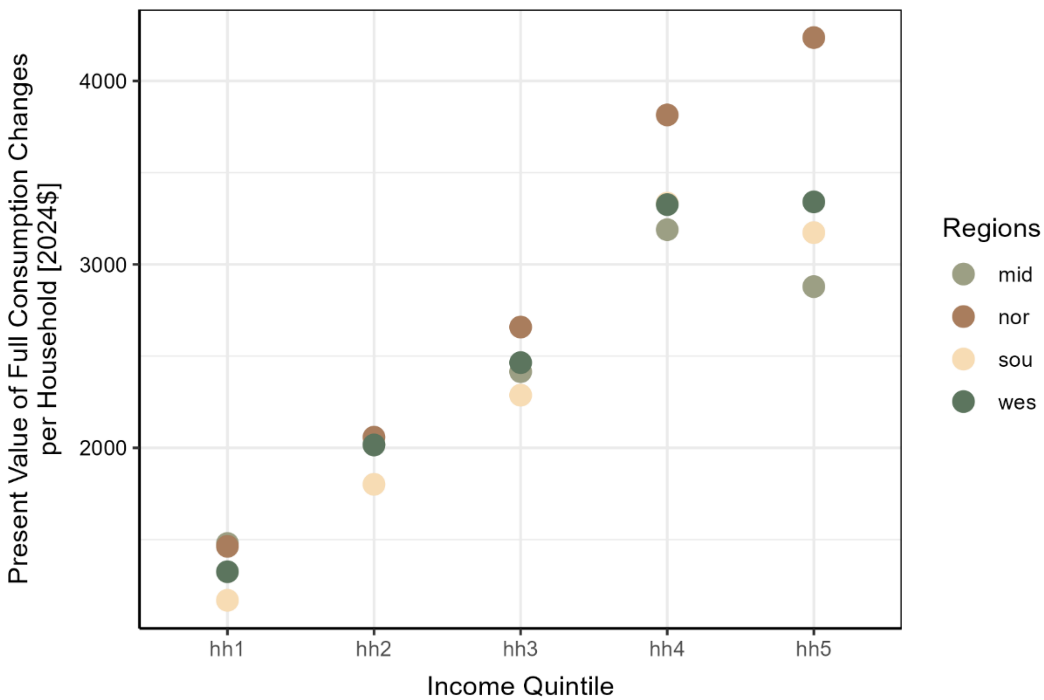

Figure 5-4 Distribution of the Present Value of the Change in Real Full Consumption (2026 to 2047), 2024 dollars

SAGE's representation in the incidence of regulatory changes on domestic households is affected by its ability to distinguish between the sources and uses of income for domestic and foreign consumers and asset owners. For example, SAGE distinguishes between domestic and foreign asset owners of government debt (e.g., bonds) and thus the change in the value of debt

[82] 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 the SAGE model. Specifically, we distribute the net change in government expenditures as a result of the repeal based on each average U.S. household's share of commodity consumption.

due to a regulation. It further represents the effects of trade on income earned in the U.S. and the costs of goods and services to domestic households. However, SAGE does not distinguish between the ownership of physical capital in the U.S. between domestic and foreign investment by sector – all capital is assumed to be owned by domestic households. SAGE also does not account for how the value domestic owned assets outside the U.S. may be affected by a regulatory change.

5.2.6 Limitations

The SAGE model and methodology for aligning IPM outputs for use as inputs in SAGE reflect the best available science for conducting economy-wide modeling of the final repeal. However, both the use of SAGE in a regulatory analysis and the framework for linking IPM with the SAGE model are subject to uncertainty and limitations:

- The costs of complying with many existing regulations are largely reflected in the social accounting matrix and in projections used to calibrate the SAGE model but are not distinguished from non-regulatory related costs (i.e., there is no explicit characterization of already existing regulations in the constructed baseline). Data underlying the SAGE baseline ranges from 2016 to 2020, depending on the specific source. As a result, recent changes in the economy, including new regulations, may not be captured in the source data used to calibrate the model's baseline. For these reasons, SAGE may not explicitly capture interactions that the current rules subject to this final repeal may have with compliance activities already underway to meet other existing regulatory requirements.
- Since IPM provides inputs for this SAGE analysis, the SAGE estimates are subject to many of the same uncertainties and limitations of the IPM methodology, which are detailed in Section 3. In particular, this economy-wide analysis focuses on a single illustrative compliance scenario for the current rules subject to this final repeal.
- This analysis models changes in enhanced oil recovery revenues directly within the crude oil extraction sector in SAGE. This approach captures the productivity impacts associated with changes in captured CO_2 but does not directly allocate associated changes in oil production revenues back to the electricity sector. Therefore, electricity price impacts estimated in this chapter may be overstated.

- 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, but it is limited by not being a full linkage that captures feedbacks between the models. 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 this final repeal, it is challenging to implement and not feasible at this time.
- To align IPM outputs for use as SAGE inputs, we target the estimated change in amortized payments to capital when calibrating SAGE-PE. However, because the representation of capital differs between IPM and SAGE, the projected stream of capital investments in response to the final repeal also likely differs between the two models. See Section 5.2.3.3 for a discussion of this choice.
- 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 the effect of subsidies levied on specific technologies but, because it assumes that the average effect of the subsidy on electricity prices equals the marginal effect, it may add a degree of uncertainty to the social cost estimate regarding the degree to which the subsidies interact with pre-existing distortions in the economy.
- SAGE assumes perfect competition within each sector, a standard assumption in CGE modeling used to ensure tractability. However, market power is itself a distortion because it moves private behavior away from the economically efficient outcome. Environmental regulations can also potentially affect the number of producers and the market structure of the regulated sector by raising production costs, modifying economies of scale, or affecting barriers to entry. A more concentrated market can result in higher prices and lower output, increasing the social cost of a regulation relative to what is estimated under an assumption of perfect competition.
- The economy-wide analysis is limited to an evaluation of social costs. SAGE does not currently estimate changes in emissions nor account for the economic impact of changes in environmental quality, which may interact with the effect of a policy's costs. The SAB (U.S. EPA 2017) noted that CGE models "have not achieved their potential for analysis of the

benefits of air regulations" because they do not account for potential interactions between costs and benefits. While this means that estimates from SAGE – and CGE models generally – are a partial representation of the total effects of regulation on the economy, the SAB stated that this "does not invalidate the use of CGE models to estimate costs."

5.3 Small Entity Analysis

5.3.1 Overview

For this final rule, the 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 the EPA employs in analyzing entity impacts as opposed to a "profits test," in which annualized compliance costs are calculated as a share of profits. The sales test is frequently used because revenues or sales data are commonly available for entities impacted by the EPA regulations, and profits data normally made available are often not the true profit earned by firms because of accounting and tax considerations. Also, the use of a sales test for estimating small business impacts for a rulemaking is consistent with guidance offered by the EPA on compliance with the Regulatory Flexibility Act (RFA)[83] 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.[84]

5.3.2 EGU Small Entity Analysis and Results

This section presents the methodology and results for estimating the impact of repealing the CPS requirements on small EGU entities in 2035 based on the following endpoints:

- annual economic impacts of the final rule on small entities, and
- ratio of small entity impacts to revenues from electricity generation

[83] The RFA compliance guidance to the EPA rule writers can be found at: https://www.epa.gov/sites/production/files/2015-06/documents/guidance-regflexact.pdf
[84] 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

The CPS requirements would have affected the buildout and operation of future NGCC and NGCT additions. Costs are projected to increase significantly in 2035, which is consistent with the imposition of the second phase of the NSPS requirements on new NGCC builds, and as such, the analysis focuses on this year. While IPM can provide important information about the future operation and addition of natural gas capacity over the analysis period, the model does not project actions taken by individual firms. Hence, as a proxy for the future gas capacity built by small entities the 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. The EPA reviewed historical data and planned builds since 2017 to determine the universe of NGCC and NGCT additions as outlined in EPA National Electric Energy Data System (NEEDS) v.7 database. The NEEDS database includes operational capacity in the year of publication as well as capturing planned/committed units that are likely to come online because ground has been broken, financing obtained, or other demonstrable factors indicate a high probability that the unit will be built before June 30, 2028.[85]

Based on these criteria, the EPA identified a total of 59 GW of NGCC and 15 GW of NGCT units greater than 25 MW built since 2017. Next, we determined power plant ownership information, including the name of associated owning entities, ownership shares, and each entity's type of ownership. Ownership information for these assets was obtained primarily using data from Ventyx[86], supplemented by research using S&P[87] and publicly available data.

Majority owners of power plants with affected EGUs were categorized as one of the seven ownership types.[88] 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.

[85] For details please see Chapter 4.3 IPM base case documentation, available at: https://www.epa.gov/power-sector-modeling
[86] 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
[87] The S&P database consists of detailed ownership and corporate affiliation information at the EGU level. For more information, see: www.capitaliq.spglobal.com
[88] Throughout this analysis, the EPA refers to the owner with the largest ownership share as the "majority owner" even when the ownership share is less than 51 percent.

3. **Municipal**: A municipal utility, responsible for power supply and distribution in a small region, such as a city.
4. **Sub-division**: Political subdivision utility is a county, municipality, school district, hospital district, or any other political subdivision that is not classified as a municipality under state law.
5. **Private**: Similar to an investor-owned utility, however, ownership shares are not openly traded on the stock markets.
6. **State**: Utility owned by the state.
7. **Federal**: Utility owned by the federal government.

Next, the 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).[89] In these cases, the ultimate parent entity was identified via D&B Hoover's, whether domestically or internationally owned.

The EPA followed SBA size standards to determine which non-government ultimate parent entities should be considered small entities in this analysis. These SBA size standards are specific to each industry, each having a threshold level of either employees, revenue, or assets below which an entity is considered small.[90] SBA guidelines list all industries, along with their associated North American Industry Classification System (NAICS) code[91] 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

[89] 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/en-us/products/dnb-hoovers.html.
[90] SBA's table of size standards can be located here: https://www.sba.gov/document/support--table-size-standards.
[91] North American Industry Classification System can be accessed at the following link: https://www.census.gov/naics/

5-5. This table represents the range of NAICS codes and areas of primary business of ultimate parent entities that are majority owners of potentially affected EGUs in the historical record.

Table 5-5 SBA Size Standards by NAICS Code

NAICS Codes	NAICS U.S. Industry Title	Size Standards (number of employees)
221111	Hydroelectric Power Generation	750
221112	Fossil Fuel Electric Power Generation	950
221113	Nuclear Electric Power Generation	1,150
221114	Solar Electric Power Generation	500
221115	Wind Electric Power Generation	1,150
221116	Geothermal Electric Power Generation	250
221117	Biomass Electric Power Generation	550
221118	Other Electric Power Generation	650
221121	Electric Bulk Power Transmission and Control	950
221122	Electric Power Distribution	1,100
221210	Natural Gas Distribution	1,150

Note: This table is an example of the NAICS codes that comprised this analysis. For a complete list, please see the accompanying workbook. Based on size standards available at the following link: https://www.sba.gov/document/support--table-size-standards). Source: SBA, 2023.

The 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**: The EPA used the D&B Hoover's database as the primary source for information on ultimate parent entity employee numbers, revenue, and assets.[92] In parallel, the EPA also considered estimated revenues from affected EGUs based on analysis of IPM estimates for the baseline for 2035. The 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.[93] The EPA primarily relied on data from the Ventyx database and the U.S. Census Bureau to inform this determination.

[92] Estimates of sales were used in lieu of revenue estimates when revenue data was unavailable.
[93] 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, the EPA identified 19 percent of the NGCC and 22 percent of the NGCT additions over the historical period were attributed to small entities as summarized in Table 5-6 below.

Table 5-6 Historical NGCC and NGCT Additions (2017-present)

Capacity Type	Total Additions (GW)	Total Additions by Small Entities (GW)	Share of Small Entities to Total Build (%)
NGCC	59.5	11.5	19%
NGCT*	15.3	3.8	22%

Notes: (1) One small entity accounts for 1 GW of these builds (and owns 2.3 GW of currently operating capacity). (2) As the scope of the FRFA is limited to the new source performance standards, this table presents small business impacts for the capacity types of NGCC and NGCT. Small entities also own other capacity types not covered in the scope of the FRFA.

In run year 2035, a new NGCC addition can comply with the CPS requirements by implementing efficiency improvements (if it operates at an annual capacity factor of below 40 percent), installing CCS, or co-firing hydrogen. A new NGCT addition can comply with the final CPS rule through implementing efficiency improvements (if it operates at an annual capacity factor of below 25 percent), installing CCS or co-firing hydrogen. The chosen compliance strategy will be primarily a function of the unit's marginal control costs and its position relative to the marginal control costs of other units.

To attempt to account for each potential control strategy, the EPA estimates avoided compliance costs as follows:

$$C_{Compliance} = \Delta\ C_{Operating+Retrofit} + \Delta\ C_{Fuel} + \Delta\ R$$

where *C* represents a component of cost as labeled[94], and Δ R represents the change in revenues, calculated as the difference in value of electricity generation between the case including CPS requirements and the case not including CPS requirements in 2035 for projected NGCC and

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.

[94] Retrofit costs include the costs of installation of CCS.

NGCT additions (calculated separately), when the second phase of the NSPS is assumed to be active under the final rule.

Realistically, compliance choices and market conditions can combine such that an entity may actually experience a reduction in any of the individual components of cost. Under the rule, 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, the 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 scenario that did not include the CPS to the scenario that included the CPS requirements. These individual components of compliance costs were estimated as follows:

1. **Operating and retrofit costs** ($\Delta\ C_{Operating+Retrofit}$): The change in operating and retrofit costs under the final rule was estimated by taking the difference in projected FOM, VOM and retrofit capital expenditures between the IPM estimates for the final rule and the baseline for the NGCT and NGCC additions projected by the model.

2. **Fuel costs** ($\Delta\ C_{Fuel}$)**:** The change in fuel expenditures under the final rule was estimated by taking the difference in projected fuel expenditures between the IPM estimates for the final rule and the baseline for the NGCT and NGCC additions projected by the model.

3. **Revenue:** To estimate the value of electricity generated, the projected level of electricity generation is multiplied by the regional wholesale electricity price ($/MWh) projected by IPM, and the accredited capacity multiplied by the projected regional capacity price projected by IPM for the NGCT and NGCC additions projected by the model. The

difference between this value under the baseline and the final rule constitutes the estimated change in revenue.

Once the costs of the CPS requirements 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 modeling for the scenario including the CPS requirements, economic NGCC additions dispatch at lower levels relative to the scenario that does not include the CPS requirements when the second phase of the NSPS is active. As such, repeal of the CPS requirements results in a lowering of 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 the EPA on compliance with the RFA and is consistent with guidance published by the SBA's Office of Advocacy that suggests that cost as a percentage of total revenues is a metric for evaluating cost increases on small entities in relation to increases on large entities. The potential impacts, including compliance costs, of the final rule on NGCCs owned by small entities are summarized in Table 5-7. All costs are presented in 2024 dollars. The EPA estimated the annual net compliance cost savings to small entities to be approximately $143 million in 2035.

Table 5-7 Projected Impact of the Final Rule on Small Entities in 2035

EGU Ownership Type	Number of Potentially Affected Entities	Total Net Compliance Cost Savings ($2024 millions)	Number of Small Entities with Compliance Costs >=1% of Generation Revenues	Number of Small Entities with Compliance Costs >=3% of Generation Revenues
Private	8	84	0	0
Co-op	5	57	0	0
Municipal	1	2	0	0
Total	**14**	**143**	**0**	**0**

Source: IPM analysis

The EPA assessed the economic and financial impacts of the rule using the ratio of compliance costs to the value of revenues from electricity generation, focusing in particular on entities for which this measure is greater than 1 percent. Of the 14 entities that own NGCC units considered in this analysis, all are projected to experience reductions in compliance costs – i.e. none are projected to experience compliance costs greater than or equal to 1 percent of generation revenues in 2035. This final repeal will therefore not have a significant economic impact on a substantial number of small entities.

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6 COMPARISON OF BENEFITS AND COSTS

6.1 Introduction

This section provides a comparison of the costs and benefits of this action, as well as discusses unquantified impacts. The reduced expenditures on compliance costs reported in this section are not social costs; instead, we use compliance costs as a proxy for social costs. The projected real resource costs and economy-wide social costs are separately estimated and discussed in Section 3.3.4 (real resource costs) and Section 5.2 (economy-wide social costs), respectively, but those estimates are not applied in this section. Therefore, in this section, we do not account for changes in costs and benefits due to changes in economic welfare in the broader economy arising from shifts in production and consumption that may be induced by this action. Furthermore, costs and benefits due to interactions with pre-existing market distortions outside the electricity sector are omitted, as are changes in social costs that may be associated with the net change in transfers attributable to this action. Additional limitations of the analysis and sources of uncertainty are described throughout the RIA and summarized later in this section.

6.2 Methods

The EPA calculated the PV and EAV of costs for the years 2026 through 2047, using the discount rates of 3 and 7 percent beginning-of-period discount rates from the perspective of 2025. All estimates are in 2024 dollars. The calculations of PV and EAV use an annual stream of values from 2026 to 2047. As noted elsewhere in the RIA, the EPA is unable to quantify the monetized benefits associated with emissions changes.

This RIA follows the EPA's historical practice of using a technology-rich partial equilibrium model of the electricity and related fuel sectors to estimate the incremental costs of producing electricity under the requirements of major EPA power sector rules. In Section 5.2 of this RIA, we also include an economy-wide analysis that considers additional facets of the economic response to this action, including the full resource requirements of the expected compliance pathways, some of which were paid for through subsidies in the partial equilibrium analysis in the baseline (with CPS) scenario.

6.3 Results

Table 6-1 compares cost estimates and non-monetized disbenefits from this action, providing discounted values.

Table 6-1 Costs and Benefits of this Final Repeal (billion 2024 dollars, discounted to 2025) [a]

	Compliance Costs	
	3%	**7%**
PV	-160	-95
EAV	-10	-8.6
Non-Monetized Impacts[b]		
Impacts from increases in CO_2 emissions		
Impacts to human health and environment from increases in SO_2, NO_X, $PM_{2.5}$, and HAP emissions		
Impacts to water quality and availability		

[a] Values have been rounded to two significant figures and are presented no smaller than two decimal places. Values may not appear to add correctly due to rounding.
[b] Several categories of costs and benefits remain unmonetized and are not reflected in the table.
Note: The PV and EAV presented in this table are based on a 22-year analytic timeframe (i.e., 2026 to 2047) using a 2025 present value year and beginning-of-period discounting. For E.O. 14192 regulatory accounting purposes, the EPA has prepared an alternative analysis that estimates costs over a 34-year analytic timeframe covering 2026 to 2059. To do so, the EPA uses the power sector compliance costs for 2048 to 2059 from the 2050 and 2055 model year projections located in the docket. For this rule, the EPA projects that the estimated present value and annualized value of the cost savings over this discrete timeframe are approximately $102.12 billion and $7.15 billion, respectively (7% discount rate; 2024$, 2024 present value year; 2026 to 2059 time horizon; and end-of-period discounting, where the annualized value is calculated in perpetuity).

The compliance cost values in Table 6-1 above differ from the compliance cost values in Table 1-1. In Table 1-1, we present positive compliance cost values as cost savings.

6.4 Uncertainties and Limitations

Throughout the RIA, we considered several sources of uncertainty, both quantitatively and qualitatively, regarding the emissions changes, benefits, and costs estimated for this action. We summarize these discussions as well as other important uncertainties here.

Compliance costs of the baseline (with CPS): The IPM-projected cost estimates of private compliance costs provided in this analysis is intended to estimate the change in production and transmission costs to the power sector in response, in this RIA, to this final action. There are several key areas of uncertainty related to the electric power sector that are worth noting, including assumptions about electricity demand, natural gas supply and demand, longer-term planning by utilities, and assumptions about the cost and performance of controls.

Uncertainty in modeled CCS costs and CO_2 reduction efficiency: For the reasons detailed in section IV of the preamble, the EPA is finalizing the determination that CCS with 90 percent capture is not the BSER for existing long-term coal-fired steam generating units because 90 percent CCS has not been adequately demonstrated. The EPA has also determined that the costs of 90 percent CCS are not reasonable. Because it is significantly unlikely that the necessary infrastructure for CCS can be deployed by the January 1, 2032, compliance date, the EPA is finalizing the determination that the degree of emission limitation in the CPS for long-term coal-fired steam generating units is not achievable. Consequently, the EPA is repealing the requirements in the emission guidelines pertaining to long-term existing coal-fired steam generating units.

The EPA maintained CCS assumptions developed for use in the 2024 CPS final rules in the RIA. However, in order to illustrate the sensitivity of the results to assumptions about CCS, the EPA also developed a modeling scenario assuming CCS is not allowed in the model's solution set. These model runs and a memorandum describing key results are available in the docket for this action.[95]

The EPA compliance modeling indicated substantial uptake of CCS under the CPS relative to the baseline, particularly in analysis year 2035.[96] If CCS is more costly or less effective at CO_2 removal than modeled, it is possible that there would have been less CCS uptake under the CPS. As result, costs and benefits of the CPS final rule may have been different had alternative CCS cost and removal efficiency assumptions been used, and we note this conclusion as an important uncertainty in this RIA.

Monetizing CO_2-related domestic climate impacts: There are significant uncertainties related to the monetization of greenhouse gases that include, but are not limited to: the magnitude of the change in climate due to a change in GHG emissions; the relationship between

[95] Please see "IPM Sensitivity Runs Memo" available in the docket for this action.
[96] To account for parasitic load as a result of installation of CCS, IPM includes a heat rate penalty and capacity penalty on model plants that incorporate CCS as well as CCS retrofit options. These assumptions are detailed in chapter 6 of the IPM documentation, available at: https://www.epa.gov/system/files/documents/2024-04/chapter-6-co2-capture-storage-and-transport.pdf

changes in the climate and the economy and therefore, the resulting economic impacts; future economic and population growth which are important for estimating vulnerability, willingness to pay to avoid impacts, and the ability to adapt to future changes; future technological advancements that would reduce vulnerability and impacts; the share of impacts from GHG emissions that affect citizens and residents of the United States; and the appropriate discount rates to use when discounting in an intergenerational context. Consistent with the memorandum titled "Guidance Implementing Section 6 of Executive Order 14154, entitled 'Unleashing American Energy'", the EPA did not monetize impacts from changes in GHG emissions from this final action. Monetizing these impacts could potentially result in flawed decision-making due to overreliance on highly uncertain values.

Non-quantified benefits of reductions in carbon capture and sequestration (CCS) system installation and operation: The installation and operation of CCS systems can result in emissions of pollutants. A CO_2 capture plant can impact emissions of HAPs and VOCs. A reduction in installation and operation of CCS under this rule could reduce HAP and VOC emissions from CCS systems. The EPA is unable to quantify the potential emissions changes or health benefits of this change. The installation and operation of CCS systems can also impact emissions of criteria pollutants including SO_2, PM, and NO_X. In the CPS, the EPA assumed that these releases would be controlled by installation of SCR and/or FGD. This final action would therefore not be expected to alter the emissions of SO_2, PM, or NO_X due to the reduction in installation and operation of CCS.

Interaction of the action with NAAQS attainment: The projected emissions changes under this action are projected to affect ambient of $PM_{2.5}$ and ozone concentrations in parts of the U.S. Affected areas may include locations both meeting and exceeding the NAAQS for $PM_{2.5}$ and ozone. States with nonattainment areas designated as moderate or higher are required to achieve concentration reductions in those areas sufficient to attain the NAAQS. This RIA does not account for how interaction with NAAQS compliance would affect the benefits and costs projected under the final repeal.

APPENDIX A: AIR QUALITY MODELING

The EPA used photochemical modeling to create air quality surfaces [97] that captured air pollution impacts resulting from changes in NO_X, SO_2 and direct $PM_{2.5}$ emissions from EGUs in the Final Repeal scenario relative to the Baseline (with CPS). This appendix describes the source apportionment modeling and associated methods used to create air quality surfaces for the Baseline (with CPS) and Final Repeal scenarios in snapshot years that are 2030, 2035, 2040 and 2045. The EPA created air quality surfaces for the following pollutants and metrics: annual average $PM_{2.5}$; April-September average of 8-hr daily maximum (MDA8) ozone (AS-MO3).

New ozone and PM source apportionment modeling outputs were created to support analyses in the RIAs for multiple final EGU rulemaking efforts. The basic methodology for determining air quality changes is the same as that used in the RIAs from multiple previous rules (U.S. EPA, 2019, 2020a, 2020b, 2021b, 2022a). The EPA calculated EGU emissions estimates of NO_X and SO_2 for the Baseline (with CPS) and Final Repeal scenarios in the snapshot years using the Integrated Planning Model (IPM) (Section 3 of this RIA). The EPA also used IPM outputs to estimate EGU emissions of $PM_{2.5}$ based on emission factors described in U.S. EPA (2021a)[98]. This appendix provides additional details on the source apportionment modeling.

A.1 Air Quality Modeling Simulation

The air quality modeling utilized a 2022-based modeling platform which included meteorology and emissions from 2022. The air quality modeling included photochemical model simulations for a 2022 base year to provide hourly concentrations of ozone and $PM_{2.5}$ component species nationwide. In addition, source apportionment modeling was performed using this 2022 platform to quantify the contributions to ozone from NO_X emissions and to $PM_{2.5}$ from NO_X, SO_2 and directly emitted $PM_{2.5}$ emissions from EGUs on a state-by-state basis. As described below, the modeling results for 2022, in conjunction with EGU emissions data for the Baseline (with CPS) and Final Repeal scenarios in 2030, 2035, 2040 and 2045 were used to construct the air

[97] The term "air quality surfaces" refers to continuous gridded spatial fields using a 12 km grid resolution.
[98] 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

quality surfaces that reflect the influence of emissions changes between the Baseline (with CPS) and Final Repeal scenarios in each year.

The air quality model simulation (i.e., model run) was performed using the Comprehensive Air Quality Model with Extensions (CAMx) version 7.20[99] (Ramboll, 2022). 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.

CAMx requires a variety of input files that contain information pertaining to the modeling domain and simulation period. These include gridded, hourly emissions estimates and meteorological data, and initial and boundary concentrations as described below.

The Weather Research Forecast Model (WRF) was applied for the entire year of 2022 to generate meteorological data supporting emissions and photochemical modeling applications for 2022. WRF was evaluated to ensure that its output fields reasonably represent the actual meteorological conditions during the modeling period. Identifying and quantifying these output fields allows for a downstream assessment of how the air quality modeling results are impacted by the meteorological data. WRF model setup and evaluation for 2022 is described in detail in EPA (2024).

The meteorological data generated by the WRF simulations were processed using wrfcamx v5.2 meteorological data processing program to create 35-layer gridded model-ready meteorological inputs to CAMx. During the wrfcamx processing, vertical eddy diffusivities (Kv) were calculated using the Yonsei University (YSU) (Hong et al., 2006) mixing scheme. A minimum Kv of 0.1 m^2/sec was used, except for urban grid cells where the minimum Kv was reset to 1.0 m^2/sec within the lowest 200 m of the surface to enhance mixing associated with the nighttime “urban heat island” effect.

The 2022 emissions include point sources, nonpoint sources, onroad mobile sources, nonroad mobile sources, biogenic emissions, and fires for the U.S., Canada, and Mexico. Detailed description of the data and methods used to create 2022 emissions are available from EPA (2025). The primary emissions processing tool used to create the model-ready emissions

[99] CAMx was run with the following configuration options: CB6r5_CF2E chemistry, ZHANG03 dry deposition scheme, NH_3 Rscale = 0, bi-directional ammonia flux turned off

was the Sparse Matrix Operator Kernel Emissions (SMOKE) modeling system. SMOKE version 5.1. SMOKE was used to generate emissions files for a 12-km grid covering the continental U.S. A separate photochemical model, the Community Multiscale Air Quality Model (CMAQv5.4) was run to generate biogenic VOC, soil NO, lightning NOx, and fertilizer NH_3.

Two nested CMAQ simulations were conducted to create boundary conditions for the 12-km resolution CAMx simulation. First CMAQv5.4 was run on a hemispheric scale (H-CMAQ). This version of CMAQ is described in more detail by Sarwar et al. (2024). This version of the model augments the v5.4 Carbon Bond 6 chemistry[100] with aerosol nitrate photolysis as proposed by Shah et al. (2023). The H-CMAQ simulation used meteorology derived from a 108 km resolution WRFv4.4.2 simulation using a polar stereographic grid. Both WRF and CMAQ utilize 44 vertical layers extending up to a zero-flux top at 50 hPa. Stratospheric ozone fluxes were parameterized based on potential vorticity. The H-CMAQ simulations used emissions included the following: 1) biogenic VOC and soil NOx emissions developed from emission files for Copernicus Atmosphere Monitoring Service's (CAMS) as documented in EPA (2021c); 2) wildfire emissions were developed globally from FINN v1.5 (Wiedinmyer et al., 2011); 3) anthropogenic emissions derived from the Hemispheric Transport of Air Pollutants Task Force Phase 3 harmonized emissions (Crippa et al., 2023). The hemispheric CMAQ results were archived at hourly resolution for all 44 layers over the whole domain for initial and boundary conditions. The standard CMAQ preprocessors ICON and BCON were used to extract initial and lateral boundary conditions for the 36 km domain shown in Figure A-1 and vertically interpolate to a 35-layer vertical structure used for the 36km simulation. CMAQv5.4 (U.S. EPA, 2022b)[101] was then run for the 36 km model domain using boundary conditions generated from the H-CMAQ simulation. Emissions inputs and meteorology for the 36-km CMAQ simulation use the same configurations as described above for the CAMx simulations. Results from the 36 km resolution CMAQ simulation were extracted to create boundary conditions for the 12 km resolution CAMx simulation.

[100] The Carbon Bond 6 chemistry included full halogen chemistry as described in Sarwar et al (2015).
[101] The 36 km resolution CMAQ simulation did not include nitrate photolysis chemistry which is more important for hemispheric and global runs.

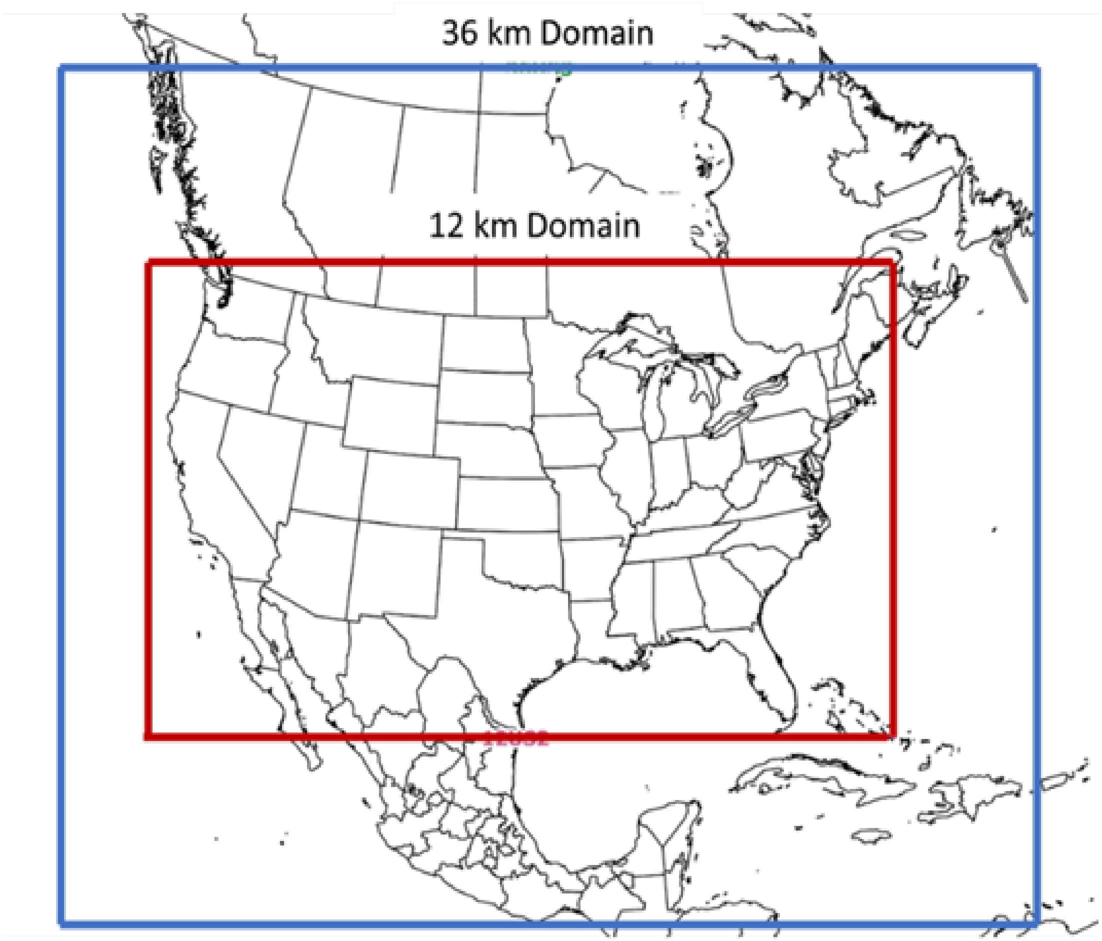

Figure A-1 Air Quality Modeling Domain

Model predictions of ozone and $PM_{2.5}$ concentrations were compared against ambient measurements. Model performance statistics were calculated as described in Simon et al (2012). Statistics were generated for each of the nine National Oceanic and Atmospheric Administration (NOAA) climate regions[102] of the 12 km U.S. modeling domain. The regions[103] include the Northeast, Ohio Valley, Upper Midwest, Southeast, South, Southwest, Northern Rockies/Plains,

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[102] NOAA, National Centers for Environmental Information scientists have identified nine climatically consistent regions within the contiguous U.S., http://www.ncdc.noaa.gov/monitoring-references/maps/us-climate-regions.php.
[103] The nine climate regions are defined by States where: Northeast includes CT, DE, ME, MA, MD, NH, NJ, NY, PA, RI, and VT; Ohio Valley includes IL, IN, KY, MO, OH, TN, and WV; Upper Midwest includes IA, MI, MN, and WI; Southeast includes AL, FL, GA, NC, SC, and VA; South includes AR, KS, LA, MS, OK, and TX; Southwest includes AZ, CO, NM, and UT; Northern Rockies includes MT, NE, ND, SD, WY; Northwest includes ID, OR, and WA; and West includes CA and NV.

Northwest, and West[104] as were originally identified in Karl and Koss (1984). Performance statistics are provided in Table A-1 and Table A-2.

The model performance statistics indicate that the 8-hour daily maximum ozone concentrations predicted by the 2022 CAMx simulation closely reflect the corresponding monitored concentrations in space and time in each subregion of the 12-km modeling domain. The 8-hour daily maximum ozone at the AQS and CASTNet sites during 2022 is within ± 15 percent for all climate regions and seasons (regional/seasonal normalized mean bias ranging between -8 to 12 percent). The CAMx annual Normalized Mean Bias for $PM_{2.5}$ predictions are within ± 30 percent for all regions except the Northern Rockies & Plains (NMB: -37 percent) at AQS sites (Table A-2). Correlation coefficients over the annual period between $PM_{2.5}$ model predictions and observations were greater than 0.4 in seven of nine regions for AQS sites. These performance statistics are generally within the range of model performance statistics reported in the scientific literature for state-of-the-science photochemical models (Simon et al., 2012; Kelly et al, 2019) and recent regulatory applications (U.S. EPA, 2019, 2020a, 2020b, 2021b, 2022a). This simulation is suitable for use in national scale applications. Ozone and $PM_{2.5}$ model evaluations showed model performance that was adequate for applying these model simulations for the purpose of creating air quality surfaces to estimate summertime ozone and annual $PM_{2.5}$ concentration changes for this action.

Table A-1 CAMx Performance Statistics 8-hour daily maximum ozone at AQS Sites in 2022

Region	Season	N	Mean Observation (ppb)	Mean Model (ppb)	Mean Bias (ppb)	Normalized Mean Bias (%)	Normalized Mean Error (%)	Root Mean Square Error (ppb)	r
Northeast	All	52703	39.8	41.3	1.5	3.9	11.3	5.84	0.84
	Winter	7926	33.9	33.3	-0.6	-1.9	10.3	4.55	0.77
	Spring	16165	42.5	42.9	0.4	1.0	9.2	5.11	0.76
	Summer	16222	44.8	47.6	2.9	6.4	11.4	6.63	0.83
	Fall	12390	33.5	36.1	2.6	7.9	15.0	6.33	0.78
Southeast	All	48275	39.4	41.8	2.4	6.0	12.4	6.39	0.82
	Winter	6842	36.7	38.4	1.7	4.6	10.1	4.92	0.81
	Spring	15220	43.9	44.2	0.2	0.5	9.2	5.26	0.83

[104] Most monitoring sites in the West region are located in California, therefore statistics for the West will be mostly representative of California ozone air quality.

	Summer	14520	37.9	42.2	4.3	11.5	16.8	8.03	0.81
	Fall	11693	37.2	40.3	3.1	8.4	13.0	6.20	0.82
Ohio Valley	All	60934	41.6	43.7	2.2	5.2	11.8	6.33	0.83
	Winter	5499	30.9	33.0	2.0	6.6	12.7	5.00	0.83
	Spring	20427	42.7	43.9	1.2	2.7	9.6	5.35	0.78
	Summer	20107	46.4	49.7	3.3	7.0	12.8	7.45	0.76
	Fall	14901	37.4	39.6	2.2	5.8	13.5	6.37	0.80
Upper Midwest	All	24294	40.2	40.5	0.3	0.7	10.8	5.64	0.83
	Winter	1492	33.3	32.8	-0.5	-1.5	9.8	4.20	0.77
	Spring	8201	42.0	41.6	-0.4	-1.0	8.7	4.71	0.80
	Summer	8620	43.4	43.8	0.4	0.9	11.3	6.29	0.80
	Fall	5981	34.8	36.0	1.2	3.4	13.7	6.11	0.79
South	All	45543	40.5	40.8	0.3	0.6	13.0	6.93	0.82
	Winter	9623	33.7	34.5	0.9	2.6	11.1	4.84	0.86
	Spring	12336	44.2	44.2	0.0	0.0	11.4	6.64	0.77
	Summer	12064	41.3	42.1	0.9	2.1	16.4	8.56	0.78
	Fall	11520	41.5	40.9	-0.6	-1.5	12.7	6.79	0.84
Southwest	All	46026	48.0	46.3	-1.6	-3.4	11.5	7.30	0.74
	Winter	10447	39.2	38.7	-0.5	-1.4	13.8	7.15	0.56
	Spring	11922	51.1	50.0	-1.1	-2.1	9.6	6.42	0.61
	Summer	12266	55.8	52.2	-3.6	-6.4	12.5	9.08	0.51
	Fall	11391	44.3	43.1	-1.2	-2.6	10.7	6.02	0.76
Northern Rockies & Plains	All	16891	42.1	40.3	-1.8	-4.3	11.3	6.10	0.75
	Winter	4042	38.0	35.1	-2.9	-7.6	12.6	6.02	0.65
	Spring	4278	44.6	43.0	-1.5	-3.4	9.1	5.36	0.64
	Summer	4335	47.1	45.9	-1.2	-2.6	11.8	7.03	0.64
	Fall	4236	38.3	36.7	-1.6	-4.1	12.0	5.86	0.76
Northwest	All	6337	37.7	38.3	0.7	1.8	14.0	6.96	0.77
	Winter	803	32.3	31.8	-0.5	-1.5	18.8	7.76	0.67
	Spring	1672	39.1	40.0	1.0	2.5	11.6	5.90	0.63
	Summer	2521	39.1	39.5	0.5	1.2	13.7	7.19	0.81
	Fall	1341	36.5	37.9	1.3	3.6	15.2	7.21	0.75
West	All	60629	44.5	43.8	-0.7	-1.6	13.4	7.93	0.80
	Winter	13437	34.9	38.0	3.1	8.8	17.4	8.21	0.55
	Spring	15970	47.4	46.5	-0.9	-1.9	10.4	6.52	0.73
	Summer	16392	49.8	46.9	-2.9	-5.8	14.1	9.14	0.83
	Fall	14830	44.2	42.6	-1.6	-3.5	12.9	7.63	0.79

Table A-2 CAMx Performance Statistics for 24-hr average $PM_{2.5}$ at AQS Sites in 2022

Region	Season	N	Mean Observation (µg m-3)	Mean Model (µg m-3)	Mean Bias (µg m-3)	Normalized Mean Bias (%)	Normalized Mean Error (%)	Root Mean Square Error (µg m-3)	r
Northeast	All	94803	6.86	8.41	1.55	22.6	46.4	5.29	0.59
	Winter	22620	8.12	10.50	2.38	29.3	50.6	6.50	0.63
	Spring	24144	6.03	7.78	1.75	29.0	46.2	4.49	0.62

	Summer	24631	7.12	6.81	-0.31	-4.3	34.4	4.02	0.51
	Fall	23408	6.23	8.74	2.51	40.3	55.8	5.91	0.55
Southeast	All	73423	7.67	7.75	0.08	1.1	34.4	3.75	0.59
	Winter	17747	7.91	9.04	1.13	14.3	38.4	4.37	0.65
	Spring	18413	7.81	7.72	-0.09	-1.2	32.0	3.64	0.63
	Summer	18996	7.63	6.85	-0.78	-10.2	34.7	3.67	0.42
	Fall	18267	7.33	7.46	0.14	1.9	32.6	3.26	0.62
Ohio Valley	All	87586	8.24	8.41	0.17	2.1	32.1	3.96	0.63
	Winter	21179	8.85	9.48	0.63	7.1	35.5	4.46	0.68
	Spring	22061	7.32	7.80	0.47	6.5	30.2	3.10	0.71
	Summer	22341	8.66	7.61	-1.05	-12.1	30.5	4.11	0.38
	Fall	22005	8.15	8.81	0.66	8.1	32.1	4.08	0.69
Upper Midwest	All	50413	7.33	7.03	-0.30	-4.1	34.1	3.67	0.71
	Winter	12399	8.35	8.20	-0.15	-1.8	34.2	4.08	0.72
	Spring	12210	6.35	6.57	0.22	3.5	36.1	3.51	0.68
	Summer	12422	6.78	5.41	-1.38	-20.3	36.2	3.52	0.42
	Fall	13382	7.79	7.89	0.09	1.2	30.9	3.54	0.81
South	All	50911	8.62	6.81	-1.81	-21.0	41.8	5.43	0.37
	Winter	12261	7.40	7.16	-0.24	-3.2	40.9	4.64	0.48
	Spring	12861	9.06	7.30	-1.76	-19.5	39.0	5.08	0.49
	Summer	12952	9.54	5.16	-4.38	-45.9	53.2	7.43	0.17
	Fall	12837	8.43	7.65	-0.78	-9.3	32.6	3.86	0.57
Southwest	All	40373	6.42	4.84	-1.59	-24.7	51.8	5.32	0.35
	Winter	9912	8.01	6.11	-1.91	-23.8	59.5	7.47	0.32
	Spring	10299	5.96	5.17	-0.79	-13.2	45.6	4.42	0.29
	Summer	10111	5.89	3.24	-2.65	-45.0	52.5	4.48	0.16
	Fall	10051	5.87	4.85	-1.01	-17.3	47.0	4.32	0.47
Northern Rockies & Plains	All	25372	5.67	3.57	-2.10	-37.0	51.2	4.75	0.64
	Winter	6135	5.28	3.02	-2.26	-42.8	56.6	4.98	0.40
	Spring	6286	4.10	3.45	-0.65	-15.9	43.9	2.65	0.46
	Summer	6522	5.74	2.91	-2.84	-49.4	55.3	4.28	0.29
	Fall	6429	7.52	4.90	-2.62	-34.8	48.2	6.32	0.76
Northwest	All	52038	7.58	7.26	-0.32	-4.2	64.0	13.60	0.58
	Winter	12806	8.13	6.85	-1.28	-15.8	76.5	8.96	0.17
	Spring	13327	3.81	5.01	1.20	31.4	73.7	5.85	0.18
	Summer	13174	5.19	4.84	-0.35	-6.7	50.6	7.60	0.49
	Fall	12731	13.46	12.55	-0.91	-6.7	58.9	24.20	0.62
West	All	72477	8.00	5.90	-2.10	-26.2	46.3	7.00	0.54
	Winter	18018	9.34	7.13	-2.21	-23.7	48.9	7.31	0.57
	Spring	18145	6.93	5.74	-1.20	-17.3	40.2	4.60	0.42
	Summer	17956	7.14	4.49	-2.65	-37.1	48.2	6.91	0.50
	Fall	18358	8.58	6.24	-2.35	-27.3	46.8	8.56	0.57

The contributions to ozone and $PM_{2.5}$ component species (e.g., sulfate, nitrate, ammonium, elemental carbon (EC), organic aerosol (OA), and crustal material[105]) from EGU emissions in individual states were modeled using the "source apportionment" tool approach. In

[105] 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.

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 contributions from the emissions in each individual tag to hourly gridded[106] 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 2022 modeled case to obtain the contributions from EGU emissions in each state to ozone and $PM_{2.5}$ component species concentrations in each 12 km model grid cell 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, 2022). The ozone source apportionment modeling was performed for the period April through September to provide data for developing spatial fields for the April through September maximum daily eight-hour (MDA8) (i.e., AS-MO3) average ozone concentration. 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-3 provides emissions that were tracked for each state-level EGU source apportionment tag.

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, Missouri, Iowa, and Ohio. These figures show how the magnitude and the spatial patterns of contributions of EGU emissions to ozone and $PM_{2.5}$ component species depend on multiple factors including the magnitude and location of emissions as well as the atmospheric conditions that influence the formation and transport of these pollutants. For instance, NO_X emissions are a precursor to both ozone and $PM_{2.5}$ nitrate. However, ozone and nitrate form under very different types of atmospheric conditions, with ozone formation occurring in locations with ample sunlight and ambient VOC concentrations while nitrate formation requires colder and drier conditions and the presence of gas-phase ammonia. California's complex terrain that tends to trap air and allow pollutant build-up combined with warm sunny summer and cooler dry winters and sources of

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

both ammonia and VOCs make its atmosphere conducive to formation of both ozone and nitrate. While the magnitude of EGU NO_X emissions from gas plus coal EGUs is substantially larger in Iowa, Missouri and Ohio than in California (Table A-3) the emissions from California lead to similar contributions to ozone and larger contributions to nitrate due to the conducive conditions in that state. California EGU SO_2 emissions in the 2022 apportionment modeling are over an order of magnitude smaller than SO_2 emissions in Iowa, Ohio and Missouri (Table A-3) leading to much smaller sulfate contributions from California EGUs than from Iowa, Ohio and Missouri EGUs. $PM_{2.5}$ Crustal Material EGU contributions in this modeling come from primary $PM_{2.5}$ emissions rather than secondary atmospheric formation. Consequently, the impacts of EGU emissions on this pollutant tend to occur closer to the EGU sources than impacts of secondary pollutants (ozone, nitrate, and sulfate) which have spatial patterns showing a broader regional impact. These patterns demonstrate how the model captures important atmospheric processes which impact pollutant formation and transport from emissions sources. Finally, Figure A-6 shows EGU ozone and $PM_{2.5}$ contributions from all contiguous U.S. EGUs. The spatial patterns of EGU contributions reflect the location and magnitude of emissions from EGU sources in 2022.

Table A-3 2022 Emissions Allocated to Each Modeled EGU State Source Apportionment Tag

State	Ozone Season NO_X (tons)	Annual NO_X (tons)	Annual SO_2 (tons)	Annual $PM_{2.5}$ (tons)
AL	8,706	16,510	3,722	1,849
AR	9,026	17,016	30,915	1,158
AZ	8,643	15,668	7,371	1,748
CA	3,091	5,875	1,431	1,139
CO	9,411	17,779	10,451	1,244
CT	1,498	3,076	661	346
DC	0	0	0	0
DE	484	911	505	157
FL	20,581	38,818	13,978	6,953
GA	8,259	20,637	9,246	2,090
IA	9,376	16,967	23,074	1,115
ID	789	1,559	87	202
IL	9,975	20,576	45,355	1,657
IN	17,407	41,681	35,236	4,955
KS	7,675	13,555	4,391	1,042
KY	15,405	31,990	45,010	3,056
LA	17,347	31,108	27,677	3,190

MA	2,879	5,584	1,214	303
MD	2,164	4,405	3,837	513
ME	1,725	3,594	1,365	566
MI	15,294	29,160	43,848	1,813
MN	6,938	14,492	5,656	830
MO	18,773	48,206	95,515	3,647
MS	9,477	16,334	3,465	1,605
MT	4,653	10,460	7,755	1,300
NC	13,804	26,866	10,241	2,125
ND	14,373	28,899	33,754	2,577
NE	10,737	20,179	44,275	492
NH	572	1,504	541	210
NJ	2,406	4,835	741	504
NM	5,794	10,125	2,731	1,346
NV	2,571	4,488	3,714	1,221
NY	7,418	13,762	2,996	1,498
OH	11,742	31,934	68,460	4,779
OK	11,060	18,700	12,780	1,085
OR	1,250	2,775	158	502
PA	10,562	27,252	40,227	4,678
RI	162	302	10	82
SC	7,299	14,017	7,192	2,169
SD	753	1,144	784	28
TN	4,752	8,262	10,144	1,803
TX	52,832	93,615	129,263	12,484
UT	15,267	28,092	8,808	1,774
VA	6,619	12,598	2,663	1,859
VT	75	194	2	44
WA	3,399	7,659	1,537	706
WI	5,815	10,986	4,586	838
WV	14,379	30,158	45,043	5,226
WY	13,119	26,412	27,003	1,299

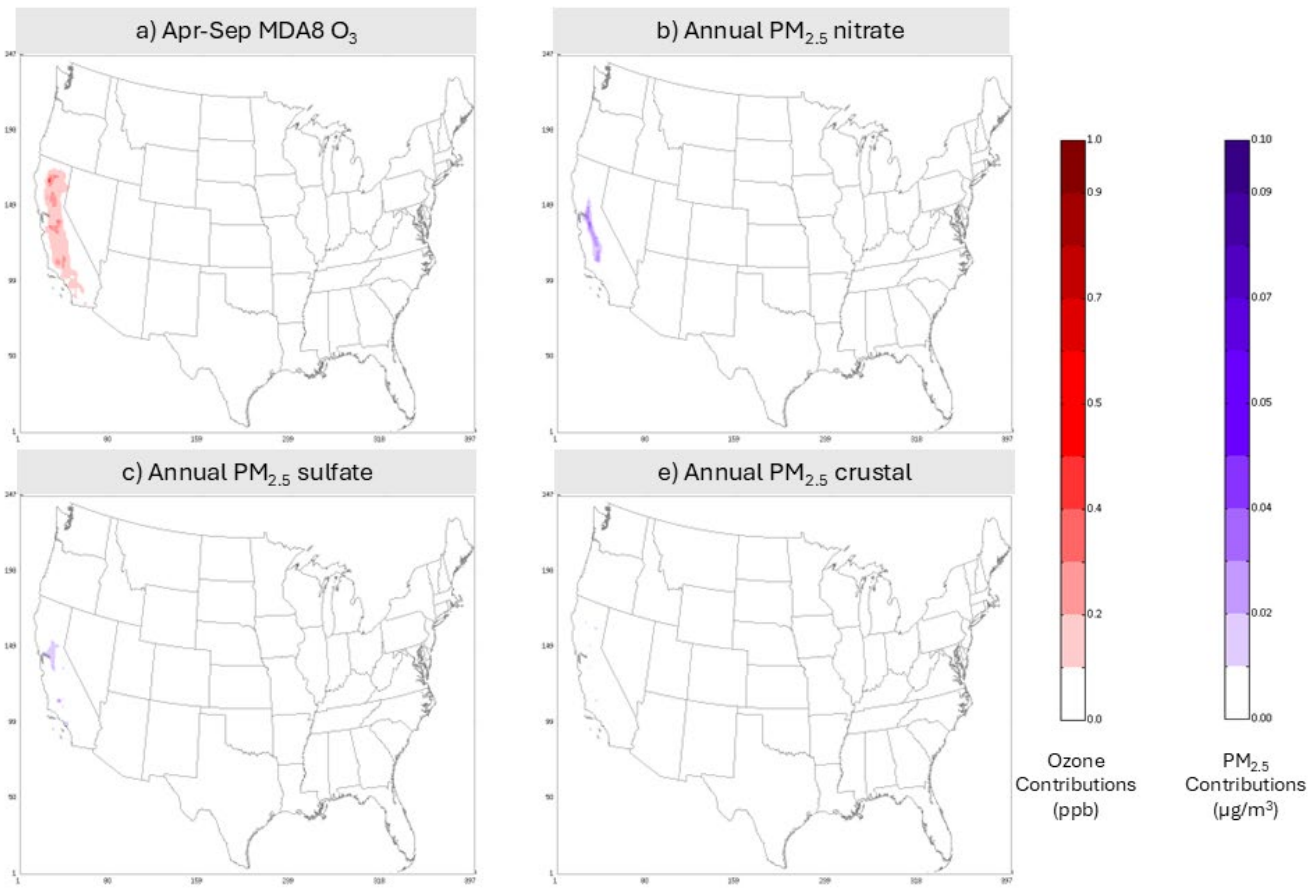

Figure A-2 Maps of California EGU tag contributions to a) April-September seasonal average 8-hour daily maximum ozone (ppb); b) annual average $PM_{2.5}$ nitrate ($\mu g/m^3$); c) annual average $PM_{2.5}$ sulfate ($\mu g/m^3$); d) annual average $PM_{2.5}$ crustal material ($\mu g/m^3$)

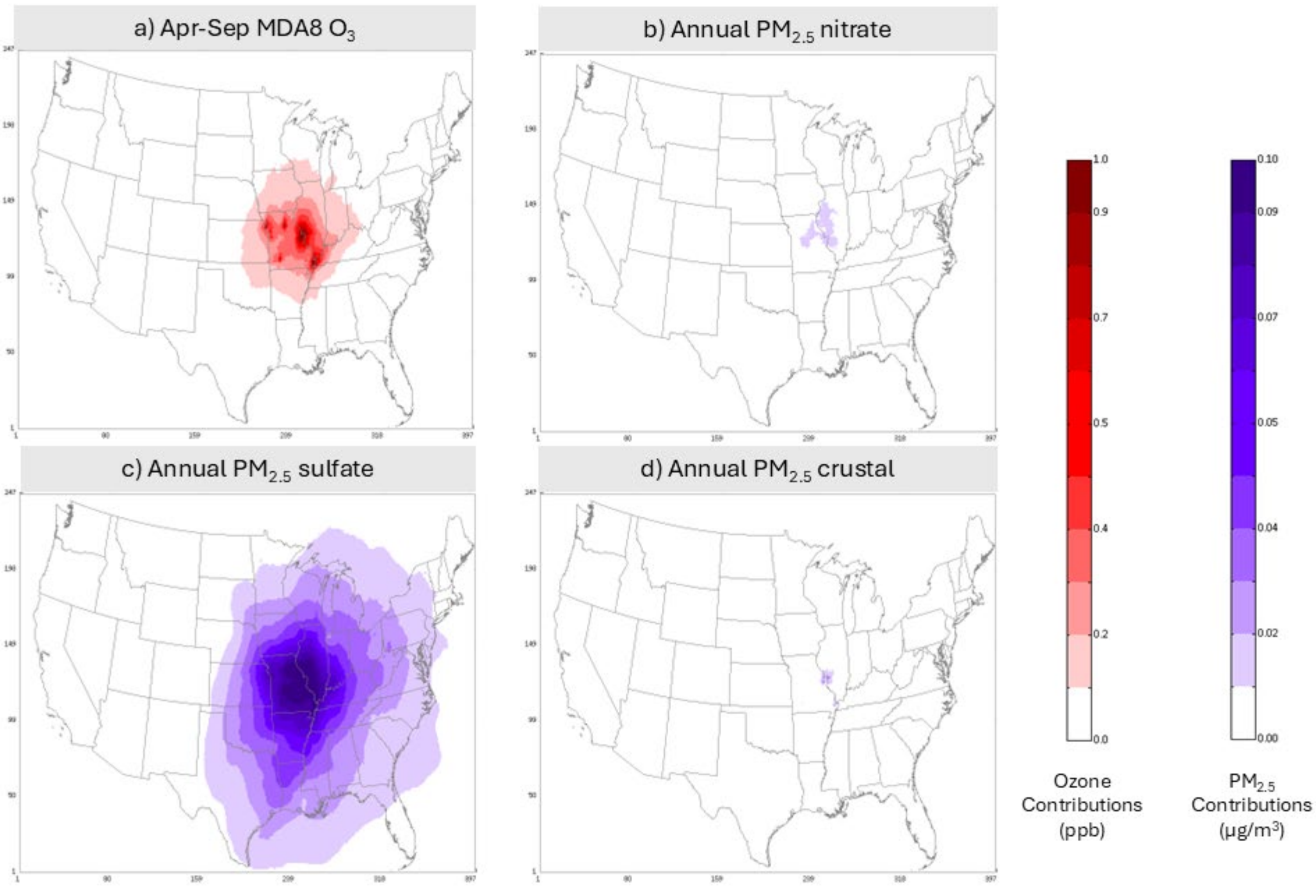

Figure A-3 Maps of Missouri EGU tag contributions to a) April-September seasonal average 8-hour daily maximum ozone (ppb); b) annual average $PM_{2.5}$ nitrate ($\mu g/m^3$); c) annual average $PM_{2.5}$ sulfate ($\mu g/m^3$); d) annual average $PM_{2.5}$ crustal material ($\mu g/m^3$)

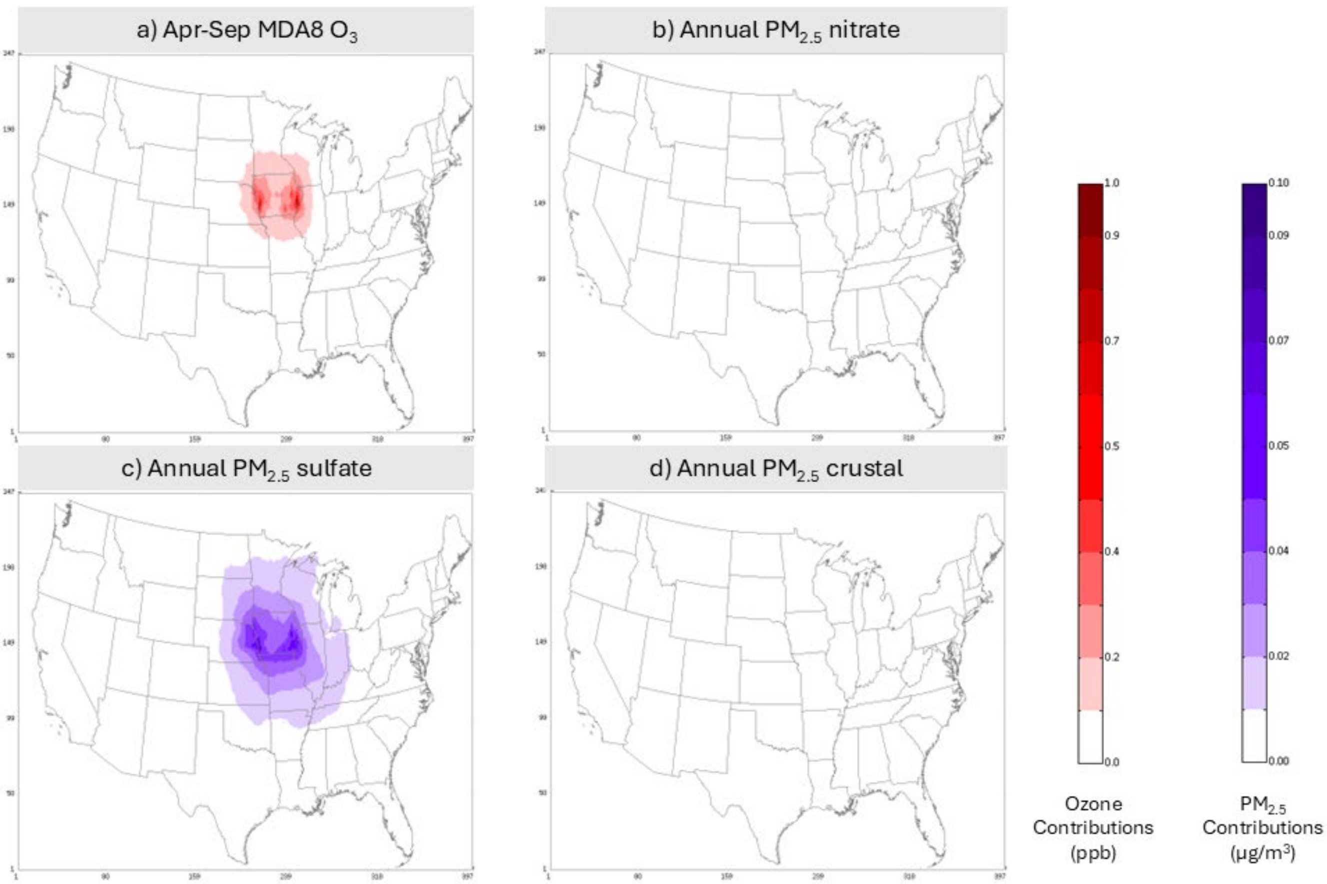

Figure A-4 Maps of Iowa EGU tag contributions to a) April-September seasonal average 8-hour daily maximum ozone (ppb); b) annual average $PM_{2.5}$ nitrate (µg/m^3); c) annual average $PM_{2.5}$ sulfate (µg/m^3); d) annual average $PM_{2.5}$ crustal material (µg/m^3)

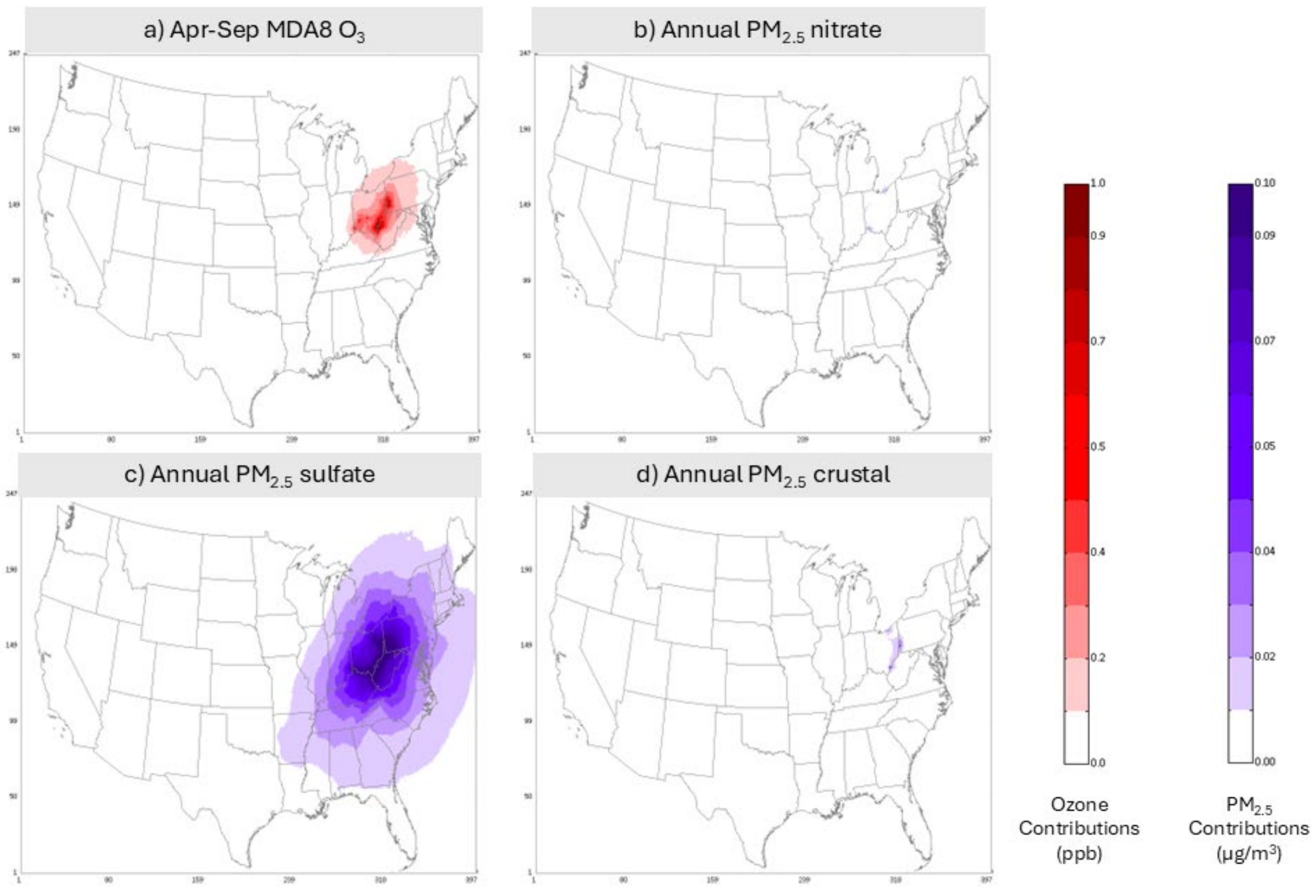

Figure A-5 Maps of Ohio EGU tag contributions to a) April-September seasonal average 8-hour daily maximum ozone (ppb); b) annual average $PM_{2.5}$ nitrate (µg/m^3); c) annual average $PM_{2.5}$ sulfate (µg/m^3); d) annual average $PM_{2.5}$ crustal material (µg/m^3)

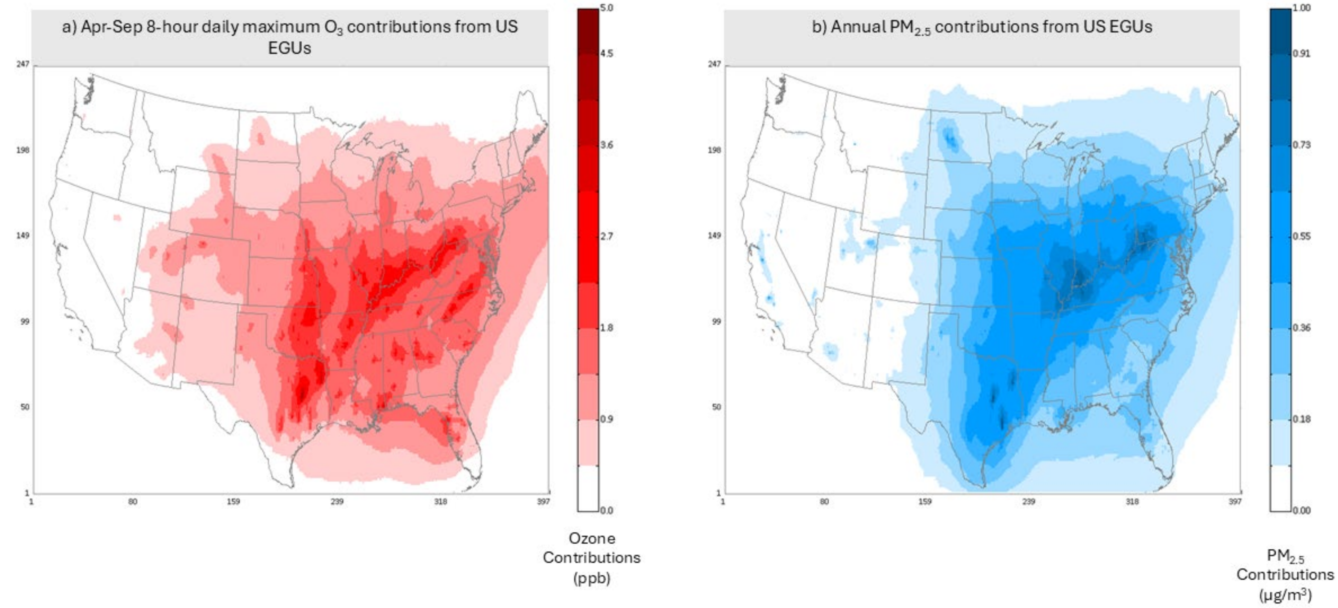

Figure A-6 Maps of National EGU Tag contributions to April-September Seasonal Average 8-hour daily maximum ozone (ppb) and Annual Average $PM_{2.5}$ ($\mu g/m^3$) from all tagged EGUs

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 2022 base year modeling. The foundational data include (1) ozone and speciated $PM_{2.5}$ concentrations in each model grid cell from the 2022 base year modeling, (2) contributions of 2022 EGU emissions to ozone and speciated $PM_{2.5}$ concentrations in each model grid cell, (3) 2022 emissions from EGUs that were inputs to the contribution modeling (Table A-3), and (4) the EGU emissions from IPM for the Baseline (with CPS) and Final Repeal scenarios in each snapshot year. The method to create spatial fields applies scaling factors to gridded 2022 source apportionment contributions based on emissions changes between 2022 and the Baseline (with CPS) and Final Repeal scenarios in the snapshot years. This method is described in detail below.

Spatial fields of 2022 base year ozone and $PM_{2.5}$ were created based on "fusing" modeled data with measured concentrations at air quality monitoring locations. To create the spatial fields for each snapshot year emissions scenario, the fused 2022 base year model fields are used in combination with the EGU source apportionment modeling and the EGU emissions for each scenario and snapshot year. Contributions from each state EGU contribution “tag” were scaled based on the ratio of emissions in the year/scenario being evaluated to the 2022 emissions. Contributions from tags representing sources other than EGUs are held constant at 2022 levels for each of the scenarios and snapshot years. For each scenario and snapshot 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 2022 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. The AS-MO3 eVNA spatial fields are created for the 2022 base year with EPA’s software package, Software for the Modeled Attainment Test – Community Edition (SMAT-CE)[107] (U.S. EPA, 2022c) using 5 years of monitoring data (2020-2024) and the 2022 modeled data.

2. Create gridded spatial fields of total EGU AS-MO3 contributions for each combination of scenario and snapshot year evaluated.

    a. Use the EGU ozone season NO_X emissions for the 2030 Baseline (with CPS) and the corresponding 2022 modeled EGU ozone season emissions (Table A-3) to calculate the ratio of 2030 Baseline (with CPS) emissions to 2022 emissions for each EGU tag (i.e., an ozone scaling factor calculated for each state EGU tag)[108]. These scaling factors are provided in Table A-4.

[107] SMAT-CE available for download at https://www.epa.gov/scram/photochemical-modeling-tools.
[108] Preliminary testing of this methodology showed unstable results when very small magnitudes of emissions were tagged especially when being scaled by large factors. To mitigate this issue, in cases where state EGU tags were associated with no or very small emissions, tags were combined into multi-state regions.

b. Calculate adjusted gridded AS-MO3 EGU contributions that reflect differences in state EGU NO_X emissions between the 2022 base year and the 2030 Baseline (with CPS) by multiplying the ozone season NO_X scaling factors by the corresponding gridded AS-MO3 ozone contributions[109] from each state EGU tag.

c. Add together the adjusted AS-MO3 contributions for each state EGU tag to produce spatial fields of adjusted EGU totals for the 2030 Baseline (with CPS) scenario[110].

d. Repeat steps 2a through 2c for the 2030 Baseline (with CPS) and Final Repeal scenarios for each additional snapshot year. All scaling factors for the Baseline (with CPS) and Final Repeal scenarios are provided in Table A-4.

3. Create a gridded spatial field of AS-MO3 associated with IPM emissions for the 2030 Baseline (with CPS) by combining the EGU AS-MO3 contributions from step (2c) with the corresponding contributions to AS-MO3 from all other sources. Repeat for each of the EGU contributions created in step (2d) to create separate gridded spatial fields for the Baseline (with CPS) and Final Repeal scenarios for each snapshot year.

Steps 2 and 3 in combination can be represented by equation 1:

$$\begin{aligned}\text{AS-MO3}_{\mathrm{g,i,y}} &= \mathrm{eVNA}_{\mathrm{g,2022}} \\ &\times \left(\frac{C_{\mathrm{g,BC}}}{C_{\mathrm{g,Tot}}} + \frac{C_{\mathrm{g,int}}}{C_{\mathrm{g,Tot}}} + \frac{C_{\mathrm{g,bio}}}{C_{\mathrm{g,Tot}}} + \frac{C_{\mathrm{g,fires}}}{C_{\mathrm{g,Tot}}} + \frac{C_{\mathrm{g,USanthro}}}{C_{\mathrm{g,Tot}}} \right. \\ &\left. + \sum_{t=1}^{T} \frac{C_{\mathrm{EGUVOC,g,t}}}{C_{\mathrm{g,Tot}}} + \sum_{t=1}^{T} \frac{C_{\mathrm{EGUNOx,g,t}}\, S_{\mathrm{NOx,t,i,y}}}{C_{\mathrm{g,Tot}}} \right)\end{aligned} \qquad \text{Eq-1}$$

- $AS\text{-}MO3_{g,i,y}$ is the estimated fused model-obs AS-MO3 for grid-cell, "g", scenario, "i"[111], and year, "y"[112];

[109] 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 between the Baseline (with CPS) and Final Repeal scenarios, the O3V contributions remain unchanged.

[110] The contributions from the unaltered O3V tags are added to the summed adjusted O3N EGU tags.

[111] Scenario "i" can represent either the Baseline (with CPS) or the Final Repeal scenario

[112] Snapshot year "y" can represent 2030, 2035, 2040 or 2045

- $eVNA_{g,2022}$ is the 2022 base year eVNA future year AS-MO3 concentration for grid-cell "g";
- $C_{g,Tot}$ is the total modeled AS-MO3 for grid-cell "g" from all sources in the 2022 base source apportionment modeling;
- $C_{g,BC}$ is the 2022 base year AS-MO3 modeled contribution from the modeled boundary inflow;
- $C_{g,int}$ is the 2022 base year AS-MO3 modeled contribution from international emissions within the modeling domain;
- $C_{g,bio}$ is the 2022 base year AS-MO3 modeled contribution from biogenic emissions;
- $C_{g,fires}$ is the 2022 base year AS-MO3 modeled contribution from fires;
- $C_{g,USanthro}$ is the total 2022 base year AS-MO3 modeled contribution from U.S. anthropogenic sources other than EGUs;
- $C_{EGUVOC,g,t}$ is the 2022 base year AS-MO3 modeled contribution from EGU emissions of VOCs from state, "t";
- $C_{EGUNOx,g,t}$ is the 2022 base year AS-MO3 modeled contribution from EGU emissions of NO_X from tag, "t"; and
- $S_{NOx,t,i,y}$ is the EGU NO_X scaling factor for tag, "t", scenario "i", and year, "y".

PM2.5:

4. Create fused spatial fields of 2022 base year annual $PM_{2.5}$ component species incorporating information from the air quality modeling and from ambient measured monitoring data. The eVNA technique was applied to $PM_{2.5}$ component species model predictions in conjunction 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. The quarterly average $PM_{2.5}$ component species eVNA spatial fields are created for the 2022 base year with EPA's SMAT-CE software package using 5 years of $PM_{2.5}$ monitoring data (2020-2024), 3 years of $PM_{2.5}$ speciation data (2021-2023) and the 2022 modeled data.

5. Create gridded spatial fields of total EGU speciated $PM_{2.5}$ contributions for each combination of scenario and snapshot year.

    a. Use the EGU annual total NO_X, SO_2, and $PM_{2.5}$ emissions for the 2030 Baseline (with CPS) scenario and the corresponding 2022 base year modeled EGU NO_X, SO_2, and $PM_{2.5}$ emissions from Table A-3 to calculate the ratio of 2030 Baseline (with CPS) emissions to 2022 base year modeled emissions for each state EGU contribution tag (i.e., annual nitrate, sulfate and directly emitted $PM_{2.5}$ scaling factors calculated for each state tag)[113]. These scaling factors are provided in Table A-5 through Table A-7.

    b. 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 the 2022 base year and the 2030 Baseline (with CPS) 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[114].

    c. 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.

    d. Repeat steps 5a through 5c for the Final Repeal scenario in 2030 and for the Baseline (with CPS) and Final Repeal scenarios for each additional snapshot year. The scaling factors for all $PM_{2.5}$ component species for the Baseline (with CPS) and Final Repeal scenarios are provided in Table A-5 through Table A-7.

6. Create gridded spatial fields of each $PM_{2.5}$ component species for the 2030 Baseline (with CPS) by combining the EGU annual $PM_{2.5}$ component species contributions from step (5c) with the corresponding contributions to annual $PM_{2.5}$ component species from all

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[113] Preliminary testing of this methodology showed unstable results when very small magnitudes of emissions were tagged especially when being scaled by large factors. To mitigate this issue, in cases where state EGU tags were associated with no or very small emissions, tags were combined into multi-state regions.

[114] 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 2022 base year modeled emissions and the Baseline (with CPS) and the Final Repeal scenarios in each snapshot year.

other sources. Repeat for each of the EGU contributions created in step (5d) to create separate gridded spatial fields for the Baseline (with CPS) and Final Repeal 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 water. 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 2022 base year modeling in accordance with equations from the SMAT-CE modeling software (U.S. EPA, 2022c).

Steps 5 and 6 result in Eq-2 for PM2.5 component species: sulfate, nitrate, organic aerosol, elemental carbon and crustal material.

$$\mathrm{PM}_{\mathrm{s,g,i,y}} = \mathrm{eVNA}_{\mathrm{s,g,2022}} \times \left(\frac{\mathrm{C}_{\mathrm{s,g,BC}}}{\mathrm{C}_{\mathrm{s,g,Tot}}} + \frac{\mathrm{C}_{\mathrm{s,g,int}}}{\mathrm{C}_{\mathrm{s,g,Tot}}} + \frac{\mathrm{C}_{\mathrm{s,g,bio}}}{\mathrm{C}_{\mathrm{s,g,Tot}}} + \frac{\mathrm{C}_{\mathrm{s,g,fires}}}{\mathrm{C}_{\mathrm{s,g,Tot}}} + \frac{\mathrm{C}_{\mathrm{s,g,USanthro}}}{\mathrm{C}_{\mathrm{s,g,Tot}}} + \sum_{\mathrm{t=1}}^{\mathrm{T}} \frac{\mathrm{C}_{\mathrm{EGUs,g,t}}\, \mathrm{S}_{\mathrm{s,t,i,y}}}{\mathrm{C}_{\mathrm{s,g,Tot}}} \right) \qquad \text{Eq-2}$$

- $PM_{s,g,i,y}$ is the estimated fused model-obs PM component species “s” for grid-cell, “g”, scenario, “i”[115], and year, “y”[116];
- $eVNA_{s,g,2022}$ is the 2022 base year eVNA PM concentration for component species “s” in grid-cell “g”.
- $C_{s,g,Tot}$ is the total modeled PM component species “s” for grid-cell “g” from all sources in the 2022 base year source apportionment modeling
- $C_{s,g,BC}$ is the 2022 base year PM component species “s” modeled contribution from the modeled boundary inflow;
- $C_{s,g,int}$ is the 2022 base year PM component species “s” modeled contribution from international emissions within the modeling domain;

115 Scenario “i" can represent either the Baseline (with CPS) scenario or the Final Repeal scenario.
116 Snapshot year “y” can represent 2030, 2035, 2040, or 2045

- $C_{s,g,bio}$ is the 2022 base year PM component species "s" modeled contribution from biogenic emissions;
- $C_{s,g,fires}$ is the 2022 base year PM component species "s" modeled contribution from fires;
- $C_{s,g,USanthro}$ is the total 2022 base year PM component species "s" modeled contribution from U.S. anthropogenic sources other than EGUs;
- $C_{EGUs,g,t}$ is the 2022 base year PM component species "s" modeled contribution from EGU emissions of NO_X, SO_2, or primary $PM_{2.5}$ from tag, "t"; and
- $S_{s,t,i,y}$ is the EGU scaling factor for component species "s", tag, "t", scenario "i", and snapshot 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-4 Baseline (with CPS) and Final Repeal Scenario Ozone Season NOx Scaling Factors for EGU Tags

	Baseline (with CPS)				Final Repeal			
State Tag	2030	2035	2040	2045	2030	2035	2040	2045
AL	0.66	0.65	0.65	0.18	0.66	0.63	0.63	0.50
AR	0.83	0.27	0.18	0.05	0.84	0.80	0.78	0.68
AZ	0.48	0.36	0.41	0.25	0.46	0.55	0.64	0.64
CA	0.91	1.28	1.42	0.66	0.81	1.37	1.16	0.65
CO	0.06	0.07	0.09	0.05	0.08	0.05	0.07	0.10
CT	0.87	0.88	0.00	0.00	0.89	0.79	0.00	0.00
*MD_DC	0.53	0.67	0.68	0.68	0.57	0.49	0.73	0.72
DE	0.46	1.26	0.33	0.32	0.81	0.33	0.38	0.40
FL	0.56	0.57	0.51	0.46	0.55	0.45	0.42	0.41
GA	0.60	0.47	0.49	0.28	0.62	0.76	0.78	0.76
IA	0.98	0.65	0.08	0.04	1.17	1.15	1.13	1.14
ID	1.09	1.05	0.98	0.74	1.16	1.10	1.12	1.26
IL	0.28	0.29	0.27	0.04	0.28	0.26	0.25	0.04
IN	0.69	0.38	0.38	0.13	0.69	0.69	0.69	0.45
KS	0.91	0.33	0.30	0.05	0.95	0.83	0.82	0.62
KY	0.88	0.49	0.49	0.08	0.89	0.69	0.68	0.42
LA	0.60	0.33	0.21	0.17	0.59	0.39	0.35	0.33
MA	0.83	0.79	0.78	0.76	0.82	0.76	0.79	0.76
ME	0.41	0.42	0.41	0.41	0.42	0.42	0.42	0.41
MI	0.39	0.34	0.23	0.12	0.41	0.33	0.25	0.22
MN	0.54	0.33	0.08	0.07	0.56	0.52	0.50	0.49
MO	0.58	0.37	0.28	0.03	0.59	0.60	0.59	0.58

State Tag	Baseline (with CPS)				Final Repeal			
	2030	2035	2040	2045	2030	2035	2040	2045
MS	0.26	0.27	0.26	0.08	0.26	0.23	0.20	0.15
MT	0.95	0.41	0.38	0.07	0.94	1.04	0.93	0.89
NC	0.22	0.23	0.24	0.11	0.22	0.17	0.18	0.19
ND	0.92	0.24	0.23	0.01	0.91	0.78	0.78	0.73
NE	0.79	0.44	0.24	0.05	0.93	0.89	0.89	0.86
*NH_VT	0.84	0.37	0.84	0.41	0.88	0.37	0.53	0.44
NJ	0.78	0.98	0.92	0.92	0.90	0.74	0.84	0.91
NM	0.34	0.33	0.31	0.10	0.33	0.28	0.29	0.24
NV	0.34	0.40	1.10	1.07	0.36	0.32	0.45	0.41
NY	0.68	0.66	0.42	0.42	0.69	0.61	0.42	0.42
OH	0.72	0.40	0.33	0.26	0.68	0.61	0.62	0.66
OK	0.83	0.23	0.06	0.01	0.81	0.54	0.45	0.35
OR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PA	1.24	0.82	0.61	0.48	1.20	0.98	0.84	0.86
RI	0.60	0.51	0.52	0.38	0.57	0.67	0.62	0.45
SC	1.32	0.62	0.61	0.24	1.28	1.01	1.00	0.81
SD	0.83	0.13	0.07	0.10	0.83	0.86	0.77	0.77
TN	0.25	0.14	0.18	0.17	0.25	0.14	0.18	0.17
TX	0.61	0.38	0.26	0.12	0.61	0.53	0.47	0.40
UT	0.46	0.46	0.06	0.06	0.63	0.65	0.65	0.62
VA	0.48	0.55	0.43	0.39	0.53	0.45	0.45	0.41
WA	0.28	0.35	0.47	0.39	0.28	0.32	0.28	0.24
WI	0.41	0.31	0.21	0.16	0.61	0.43	0.43	0.37
WV	1.03	0.78	0.77	0.10	1.02	1.08	1.08	0.74
WY	0.57	0.32	0.28	0.09	0.63	0.64	0.64	0.62

*States with low total EGU emissions were grouped with nearby states. In these cases, scaling factors were developed for multi-state regions.

Table A-5 Baseline (with CPS) and Final Repeal Scenario Annual NOx Scaling Factors for EGU Tags

State Tag	Baseline (with CPS)				Final Repeal			
	2030	2035	2040	2045	2030	2035	2040	2045
AL	0.76	0.78	0.75	0.16	0.75	0.73	0.72	0.55
AR	0.95	0.29	0.20	0.05	0.95	0.94	0.89	0.70
AZ	0.58	0.47	0.48	0.32	0.59	0.70	0.76	0.77
CA	1.49	1.90	1.98	1.13	1.38	1.86	1.58	1.09
CO	0.08	0.10	0.10	0.08	0.12	0.09	0.10	0.12
CT	0.90	0.84	0.00	0.00	0.92	0.77	0.00	0.00
*MD_DC	0.53	0.71	0.72	0.75	0.55	0.50	0.76	0.74

State Tag	Baseline (with CPS)				Final Repeal			
	2030	2035	2040	2045	2030	2035	2040	2045
DE	0.36	1.11	0.35	0.36	0.63	0.34	0.44	0.45
FL	0.59	0.63	0.60	0.51	0.59	0.51	0.49	0.47
GA	0.71	0.43	0.44	0.21	0.65	1.13	1.14	0.92
IA	1.16	0.80	0.10	0.04	1.44	1.43	1.41	1.34
ID	1.39	1.59	1.44	1.31	1.56	1.31	1.32	1.50
IL	0.28	0.29	0.28	0.05	0.28	0.27	0.26	0.05
IN	0.94	0.36	0.35	0.10	0.91	0.82	0.79	0.45
KS	1.14	0.42	0.38	0.05	1.19	1.06	0.94	0.66
KY	0.94	0.54	0.53	0.06	0.90	0.76	0.75	0.42
LA	0.60	0.40	0.23	0.16	0.56	0.46	0.41	0.35
MA	0.97	0.92	0.92	0.90	0.97	0.90	0.93	0.91
ME	0.50	0.48	0.46	0.44	0.51	0.47	0.47	0.42
MI	0.41	0.41	0.20	0.14	0.44	0.37	0.28	0.25
MN	0.53	0.35	0.09	0.08	0.58	0.56	0.53	0.47
MO	0.80	0.32	0.24	0.02	0.80	0.83	0.80	0.71
MS	0.34	0.35	0.30	0.09	0.35	0.27	0.25	0.17
MT	0.95	0.37	0.36	0.08	0.95	1.04	0.95	0.91
NC	0.41	0.27	0.27	0.12	0.43	0.21	0.21	0.22
ND	1.04	0.28	0.26	0.01	1.03	0.90	0.85	0.73
NE	0.91	0.53	0.28	0.05	1.11	1.07	1.07	0.94
NH	0.57	0.32	0.37	0.33	0.74	0.32	0.40	0.35
NJ	0.84	1.10	0.98	0.96	0.91	0.84	0.93	0.99
NM	0.40	0.40	0.38	0.10	0.39	0.35	0.35	0.29
NV	0.55	1.08	0.96	1.01	0.54	0.51	0.63	0.60
NY	0.75	0.72	0.48	0.48	0.74	0.64	0.48	0.48
OH	0.77	0.33	0.27	0.20	0.72	0.55	0.56	0.58
OK	0.96	0.27	0.07	0.01	0.89	0.67	0.50	0.36
OR	0.11	0.05	0.00	0.00	0.11	0.06	0.00	0.00
PA	1.01	0.72	0.53	0.42	0.97	0.88	0.78	0.80
RI	0.64	0.49	0.48	0.36	0.67	0.56	0.60	0.41
SC	1.52	0.76	0.72	0.28	1.49	1.17	1.17	0.93
SD	1.18	0.20	0.09	0.13	1.17	1.25	1.15	1.04
TN	0.30	0.17	0.19	0.15	0.30	0.17	0.21	0.16
TX	0.72	0.47	0.30	0.11	0.71	0.63	0.57	0.42
UT	0.57	0.58	0.09	0.09	0.78	0.79	0.80	0.81
VA	0.57	0.68	0.54	0.48	0.62	0.53	0.54	0.51
VT	2.16	0.47	1.75	0.49	2.31	0.47	0.57	0.52
WA	0.40	0.41	0.48	0.42	0.40	0.41	0.36	0.34
WI	0.45	0.36	0.22	0.16	0.70	0.51	0.48	0.40
WV	1.23	0.92	0.91	0.09	1.24	1.31	1.30	0.87
WY	0.63	0.35	0.30	0.09	0.71	0.72	0.72	0.69

*States with low total EGU emissions were grouped with nearby states. In these cases, scaling factors were developed for multi-state regions.

Table A-6 Baseline (with CPS) and Final Repeal Scenario Annual SO_2 Scaling Factors for EGU Tags

	Baseline (with CPS)				Final Repeal			
State Tag	2030	2035	2040	2045	2030	2035	2040	2045
AL	2.00	1.67	1.50	0.00	1.54	2.04	2.11	0.35
AR	1.12	0.09	0.09	0.01	1.11	1.12	1.12	0.94
AZ	1.53	0.80	0.79	0.00	1.51	0.61	0.60	0.61
CA	0.17	0.13	0.12	0.06	0.13	0.18	0.13	0.08
CO	0.00	0.00	0.00	0.00	0.06	0.05	0.11	0.18
CT	0.76	0.75	0.00	0.00	0.76	0.75	0.00	0.00
*MD_DC	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
DE	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16
FL	0.66	0.51	0.51	0.11	0.58	0.37	0.37	0.37
GA	0.52	0.16	0.16	0.04	0.50	0.59	0.59	0.58
IA	0.38	0.25	0.06	0.02	0.53	0.55	0.55	0.52
*OR_ID	0.88	0.90	0.72	0.72	0.92	0.75	0.56	0.56
IL	0.13	0.11	0.11	0.00	0.14	0.14	0.11	0.00
IN	1.05	0.51	0.54	0.20	1.06	0.82	0.82	0.45
KS	0.91	0.67	0.67	0.47	0.93	0.94	1.11	0.66
KY	1.09	0.37	0.39	0.00	1.05	0.99	0.97	0.61
LA	1.44	0.54	0.54	0.12	1.25	1.47	1.47	1.41
*MA_RI	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43
ME	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49
MI	0.05	0.01	0.01	0.01	0.05	0.05	0.05	0.05
MN	0.74	0.10	0.04	0.03	0.81	0.81	0.81	0.74
MO	1.41	0.19	0.11	0.00	1.53	1.56	1.52	1.40
MS	1.21	1.21	1.19	0.00	1.21	1.19	1.19	0.77
MT	1.09	0.54	0.46	0.06	1.09	1.09	0.71	0.75
NC	0.35	0.22	0.13	0.00	0.37	0.15	0.14	0.14
ND	1.08	1.11	1.11	0.02	1.08	1.12	1.04	0.90
NE	0.74	0.37	0.15	0.03	1.00	1.15	1.15	1.06
*NH_VT	0.64	0.15	0.15	0.15	1.90	0.15	0.15	0.15
NJ	1.13	1.13	1.13	1.13	1.13	1.13	1.13	1.13
NM	1.61	1.61	1.61	0.19	1.61	1.61	1.61	1.34
NV	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NY	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47
OH	0.62	0.41	0.28	0.06	0.49	0.44	0.44	0.44
OK	1.75	0.10	0.10	0.00	1.58	1.88	1.61	1.01
PA	0.69	0.31	0.23	0.01	0.65	0.63	0.38	0.37
SC	2.36	0.89	0.85	0.03	2.30	1.71	1.71	1.20

State Tag	Baseline (with CPS)				Final Repeal			
	2030	2035	2040	2045	2030	2035	2040	2045
SD	1.48	0.00	0.00	0.00	1.48	1.48	1.48	1.36
TN	0.16	0.00	0.00	0.00	0.15	0.00	0.00	0.00
TX	0.49	0.18	0.18	0.01	0.48	0.50	0.50	0.39
UT	0.41	0.36	0.00	0.00	0.62	0.62	0.59	0.59
VA	0.18	0.18	0.18	0.14	0.17	0.17	0.17	0.17
WA	0.38	0.24	0.24	0.22	0.38	0.24	0.24	0.22
WI	0.35	0.11	0.00	0.00	0.56	0.45	0.43	0.41
WV	0.91	0.83	0.80	0.00	0.94	0.84	0.80	0.43
WY	0.53	0.51	0.38	0.07	0.60	0.60	0.60	0.55

*States with low total EGU emissions were grouped with nearby states. In these cases, scaling factors were developed for multi-state regions.

Table A-7 Baseline (with CPS) and Final Repeal Scenario Annual Primary $PM_{2.5}$ Scaling Factors for EGU Tags

State Tag	Baseline (with CPS)				Final Repeal			
	2030	2035	2040	2045	2030	2035	2040	2045
AL	1.44	1.56	1.51	0.72	1.46	1.41	1.42	1.06
AR	1.21	0.66	0.47	0.16	1.21	1.17	1.11	0.85
AZ	1.00	0.90	1.07	0.88	1.24	1.46	1.73	1.79
CA	3.05	3.55	4.39	2.88	2.98	3.41	4.12	2.84
CO	0.30	0.39	0.43	0.43	0.32	0.38	0.41	0.44
CT	0.70	0.62	0.00	0.01	0.76	0.55	0.00	0.00
*MD_DC	0.71	1.29	1.69	1.94	0.87	0.74	1.80	1.79
DE	0.65	1.41	0.99	1.04	0.93	0.78	1.05	1.17
FL	0.90	0.98	1.02	0.82	0.88	0.83	0.86	0.78
GA	1.10	1.16	1.25	0.85	1.07	1.27	1.34	1.10
IA	1.54	1.12	0.30	0.18	1.63	1.59	1.47	1.47
ID	3.38	3.86	3.67	3.49	3.39	3.20	3.40	4.02
IL	0.50	0.52	0.61	0.30	0.51	0.48	0.58	0.30
IN	1.22	0.66	0.59	0.31	1.18	1.27	1.22	0.84
KS	1.28	0.73	0.68	0.08	1.39	1.39	1.26	0.85
KY	0.99	0.74	0.73	0.26	0.93	0.90	0.92	0.58
LA	0.97	0.96	0.78	0.49	0.94	0.97	0.86	0.70
MA	1.13	1.01	1.13	1.06	1.19	0.98	1.32	1.13
ME	0.31	0.30	0.31	0.29	0.31	0.30	0.31	0.27
MI	0.95	0.98	0.86	0.76	0.98	1.03	1.02	0.94
MN	0.86	0.74	0.32	0.29	0.96	0.92	1.01	0.90
MO	0.90	0.72	0.59	0.11	0.88	0.96	0.90	0.81
MS	1.11	1.19	0.96	0.30	1.14	0.80	0.64	0.41
MT	1.05	1.14	1.14	0.36	1.03	1.34	1.26	1.20

State Tag	Baseline (with CPS)				Final Repeal			
	2030	2035	2040	2045	2030	2035	2040	2045
NC	0.81	0.91	0.96	0.68	0.86	0.69	0.68	0.75
ND	1.08	1.12	1.09	0.07	1.07	1.13	1.08	0.80
NE	0.92	0.90	0.63	0.20	1.01	0.93	0.95	0.86
NH	0.85	0.33	0.46	0.38	1.08	0.33	0.58	0.45
NJ	1.15	1.77	2.00	2.05	1.25	1.43	1.89	2.30
NM	0.93	0.97	0.93	0.28	0.89	0.90	0.89	0.73
NV	1.29	1.49	1.60	1.60	1.19	1.13	1.33	1.14
NY	0.93	0.89	0.67	0.68	0.88	0.81	0.68	0.69
OH	0.85	0.71	0.67	0.60	0.75	0.71	0.70	0.78
OK	1.28	0.96	0.28	0.04	1.19	1.17	0.71	0.49
OR	0.18	0.10	0.01	0.01	0.18	0.12	0.01	0.01
PA	1.32	0.94	0.92	0.81	1.27	1.34	1.15	1.20
RI	1.46	1.40	1.42	1.29	1.47	1.52	1.59	1.37
SC	2.31	1.76	1.80	0.81	2.24	1.71	1.74	0.94
SD	8.64	3.31	1.23	2.82	8.56	9.03	8.76	8.09
TN	0.36	0.30	0.39	0.31	0.36	0.30	0.42	0.32
TX	1.02	0.96	0.73	0.31	1.01	1.04	0.99	0.71
UT	0.92	0.99	0.57	0.67	0.81	0.93	1.04	1.07
VA	0.68	0.90	0.70	0.61	0.77	0.64	0.67	0.57
VT	0.64	0.56	0.69	0.65	1.03	0.56	0.71	0.70
WA	0.95	1.05	1.12	1.00	0.95	1.04	0.82	0.77
WI	1.04	1.27	1.07	0.86	1.05	1.38	1.51	1.12
WV	1.05	1.11	1.09	0.21	1.03	1.20	1.22	0.71
WY	1.23	1.37	1.19	0.63	1.32	1.44	1.43	1.36

*States with low total EGU emissions were grouped with nearby states. In these cases, scaling factors were developed for multi-state regions.

A.4 Air Quality Surface Results

The spatial fields of Baseline (with CPS) AS-MO3 and Annual Average PM2.5 in 2030, 2035, 2040 and 2045 are presented in Figure A-7 through Figure A-14. 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 the Baseline (with CPS) spatial fields in Figure A-11 through Figure A-14 as demonstrated by the extensive areas of elevated concentrations over much of the Eastern U.S. and California which have large secondary components and hotspots near source locations such as urban areas and fires which are impacted by primary PM emissions.

Figure A-7 through Figure A-14 also present the model-predicted air quality changes between the Baseline (with CPS) and Final Repeal scenarios in 2030, 2035, 2040 and 2045 for AS-MO3 and $PM_{2.5}$. Difference in these figures are calculated as the Final Repeal scenario minus the Baseline (with CPS). While there are areas of both increases and decreases in AS-MO3 and $PM_{2.5}$ in the Final Repeal scenario compared to the Baseline (with CPS), the areas are broad regional increases in both pollutants across the Eastern US in the Final Repeal scenario in the later snapshot years of 2035, 2040, and 2045. 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-11 through Figure A-14, 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.

Figure A-15 through Figure A-18 show changes in AS-MO3 in 2030, 2035, 2040, and 2045 relative to recent 2022 conditions. Figure A-19 through Figure A-22 show changes in $PM_{2.5}$ in 2030, 2035, 2040, and 2045 relative to recent 2022 conditions. Relative to 2022 conditions, these figures indicate that ozone and $PM_{2.5}$ concentration will decline in most areas of the country for both Baseline (with CPS) and Final Repeal scenarios in each further out snapshot year, although the decline in ozone and $PM_{2.5}$ concentrations are less pronounced in the Final Repeal scenario than it would have been in the Baseline (with CPS) scenario for most snapshot years. One noticeable departure of the predicted decline in $PM_{2.5}$ relative to recent 2022 conditions is a notable increase in predicted $PM_{2.5}$ in California for both the Baseline (with CPS) and Final Repeal scenarios. The California increase compared to 2022 is explained by predictions of increased direct $PM_{2.5}$ emissions associated with increased dispatch of natural gas EGUs in California to meet expected energy demand. These predictions are very similar in the Baseline (with CPS) and Final Repeal scenarios so this predicted impact is not attributed to the final rule.

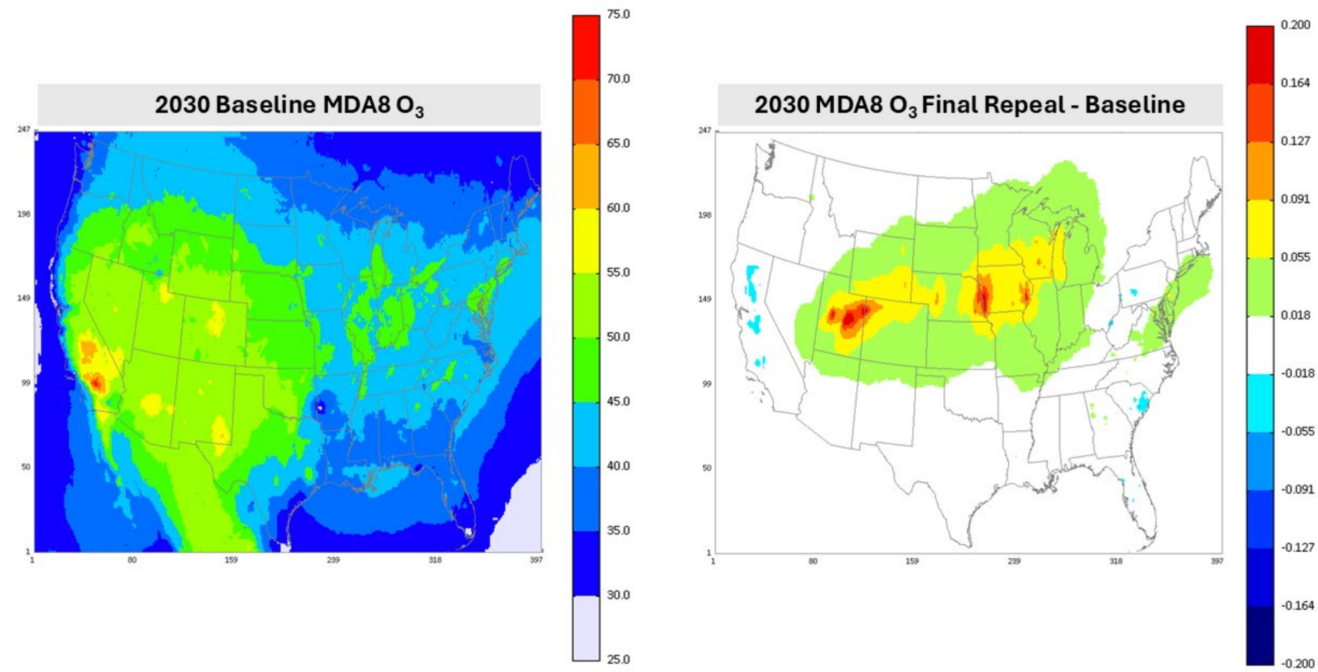

Figure A-7 Maps of ASM-O3 in 2030. Baseline (with CPS) ozone concentrations (ppb) shown on the left. Change in ozone in the Final Repeal scenario compared to Baseline (with CPS) values (ppb) shown on the right.

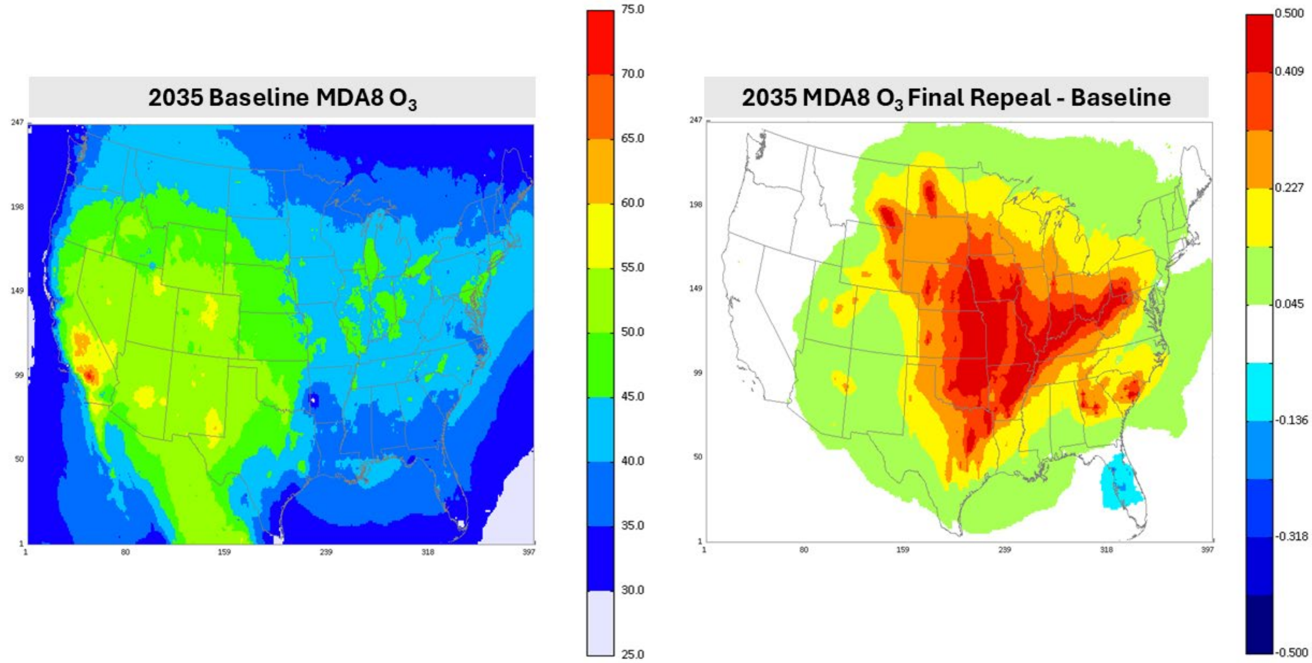

Figure A-8 Maps of ASM-O3 in 2035. Baseline (with CPS) ozone concentrations (ppb) shown on the left. Change in ozone in the Final Repeal scenario compared to Baseline (with CPS) values (ppb) shown on the right.

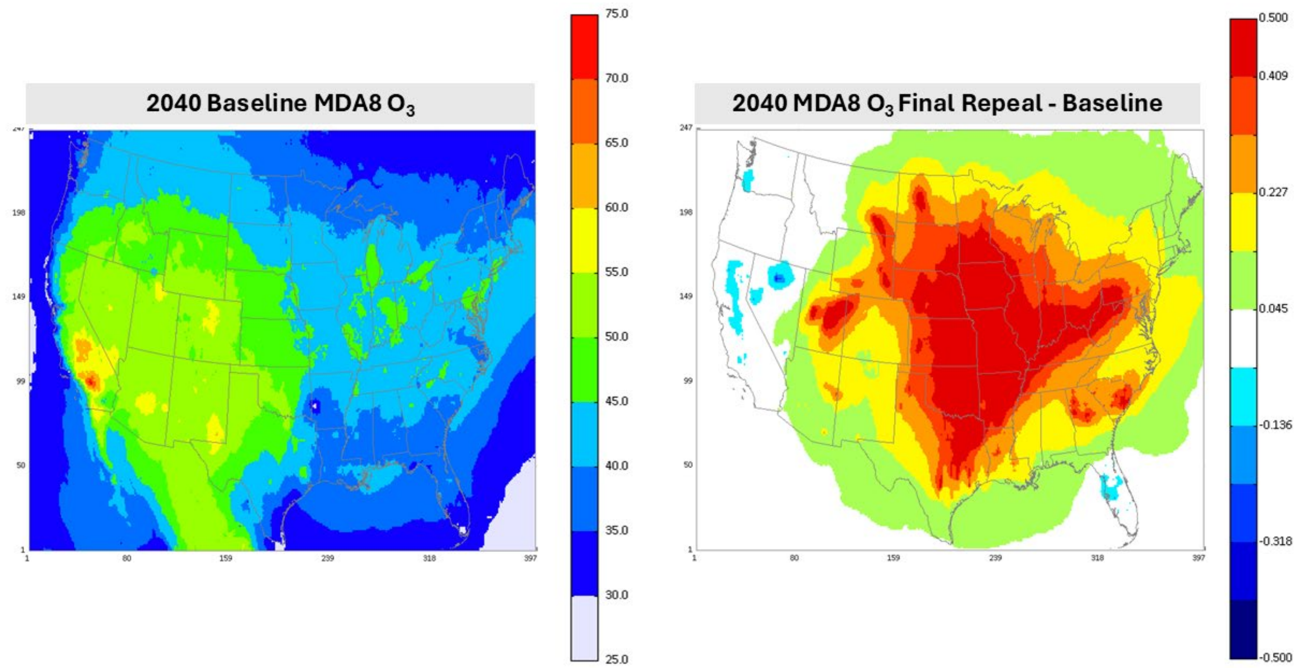

Figure A-9 Maps of ASM-O3 in 2040. Baseline (with CPS) ozone concentrations (ppb) shown on the left. Change in ozone in the Final Repeal scenario compared to Baseline (with CPS) values (ppb) shown on the right.

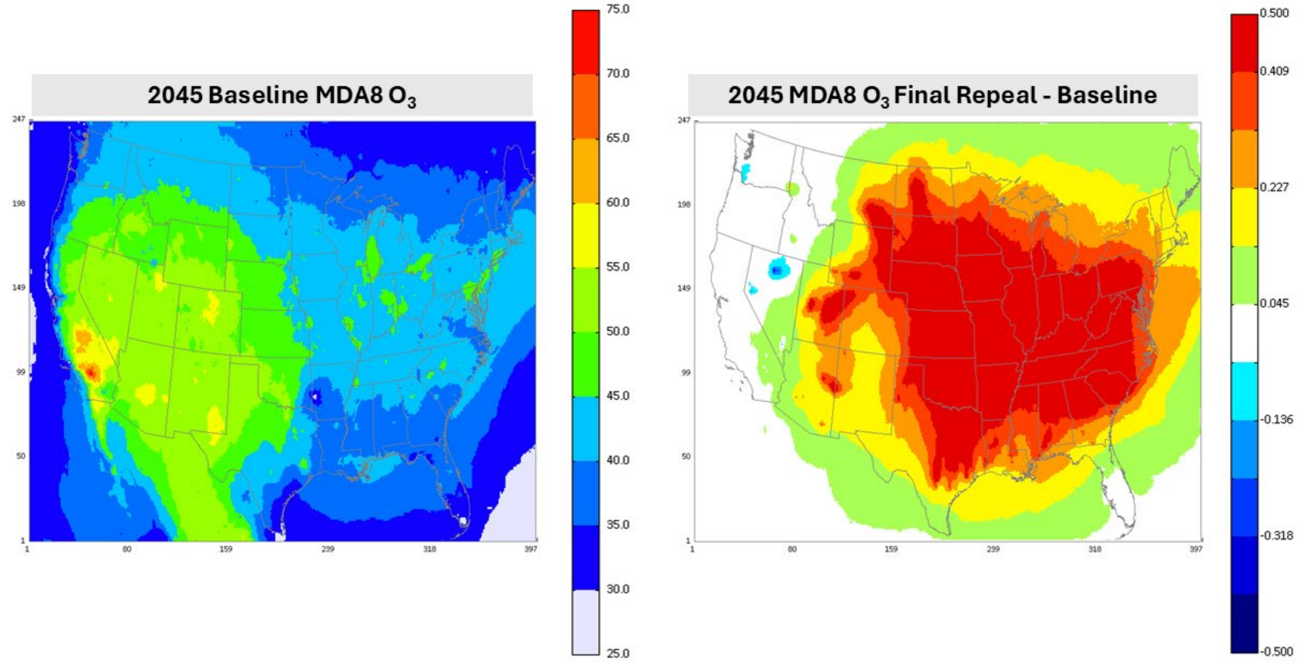

Figure A-10 Maps of ASM-O3 in 2045. Baseline (with CPS) ozone concentrations (ppb) shown on the left. Change in ozone in the Final Repeal scenario compared to Baseline (with CPS) values (ppb) shown on the right.

Color bars for Figure A-11 differ in scale (±0.1 µg/m3) from color bars used in Figure A-12 through Figure A-14 (±0.5 µg/m3).

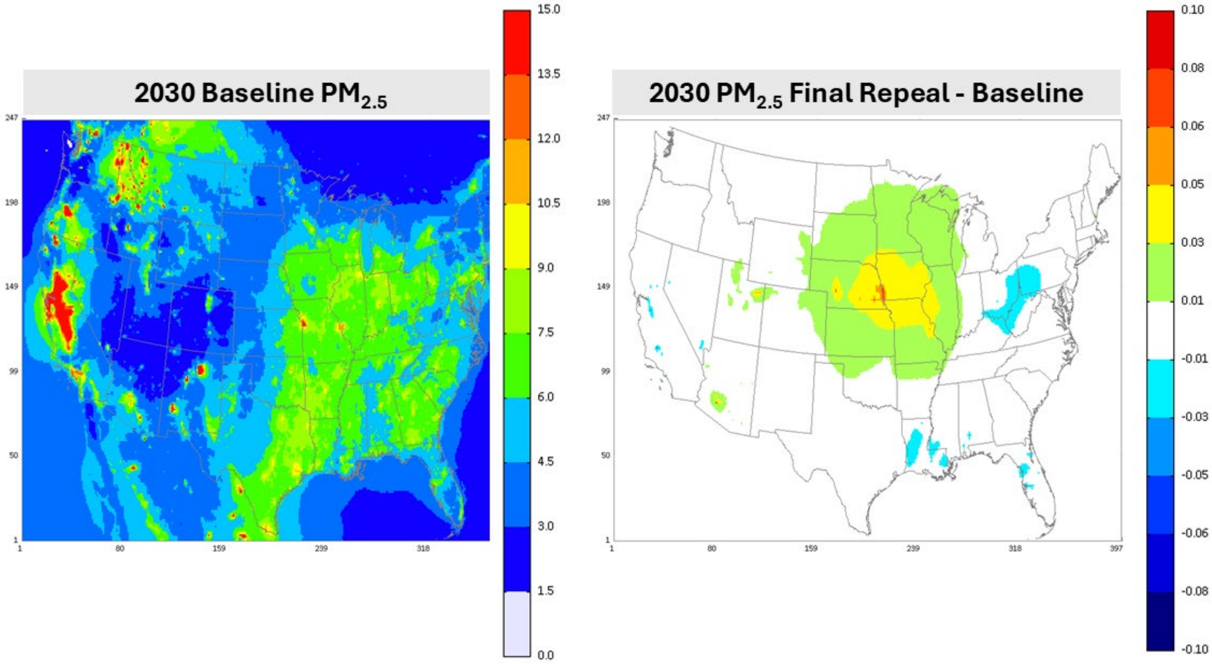

Figure A-11 Maps of PM2.5 in 2030. Baseline (with CPS) $PM_{2.5}$ concentrations (µg/m3) shown on the left. Change in $PM_{2.5}$ in the Final Repeal scenario compared to Baseline (with CPS) values (µg/m3) shown on the right.

Color bars for Figure A-11 differ in scale (±0.1 µg/m3) from color bars used in Figure A-12 through Figure A-14 (±0.5 µg/m3).

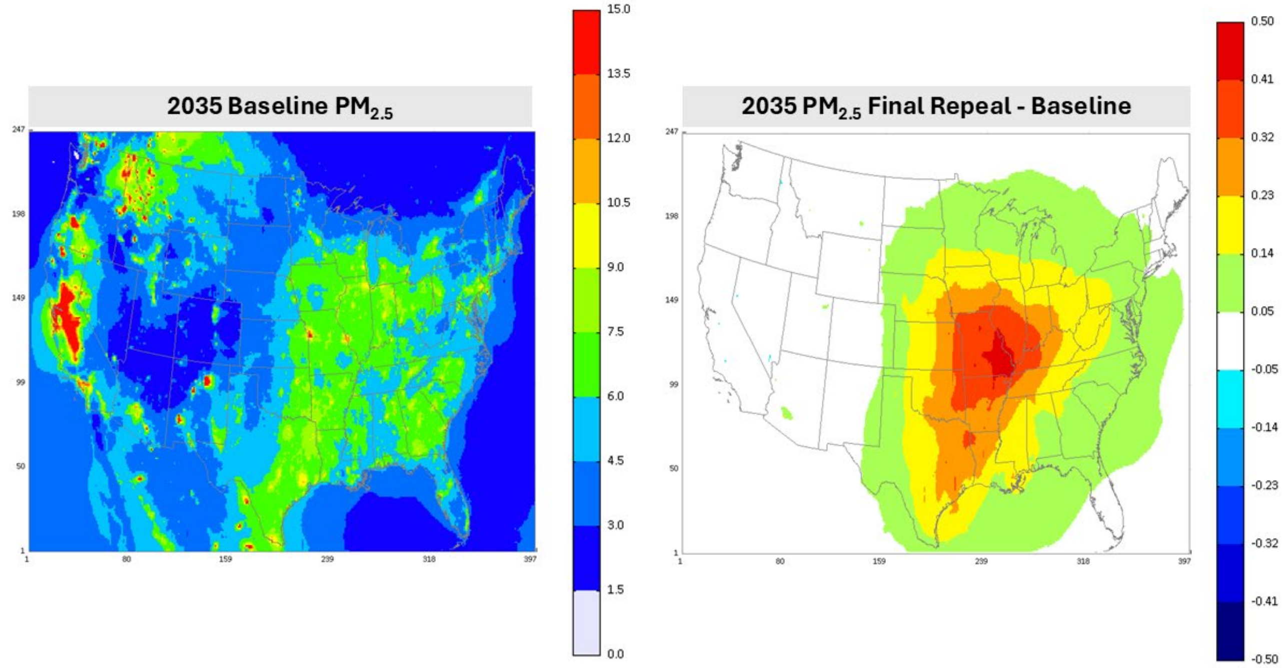

Figure A-12 Maps of PM2.5 in 2035. Baseline (with CPS) $PM_{2.5}$ concentrations (µg/m3) shown on the left. Change in $PM_{2.5}$ in the Final Repeal scenario compared to Baseline (with CPS) values (µg/m3) shown on the right.

Color bars for Figure A-11 differ in scale (±0.1 µg/m3) from color bars used in Figure A-12 through Figure A-14 (±0.5 µg/m3).

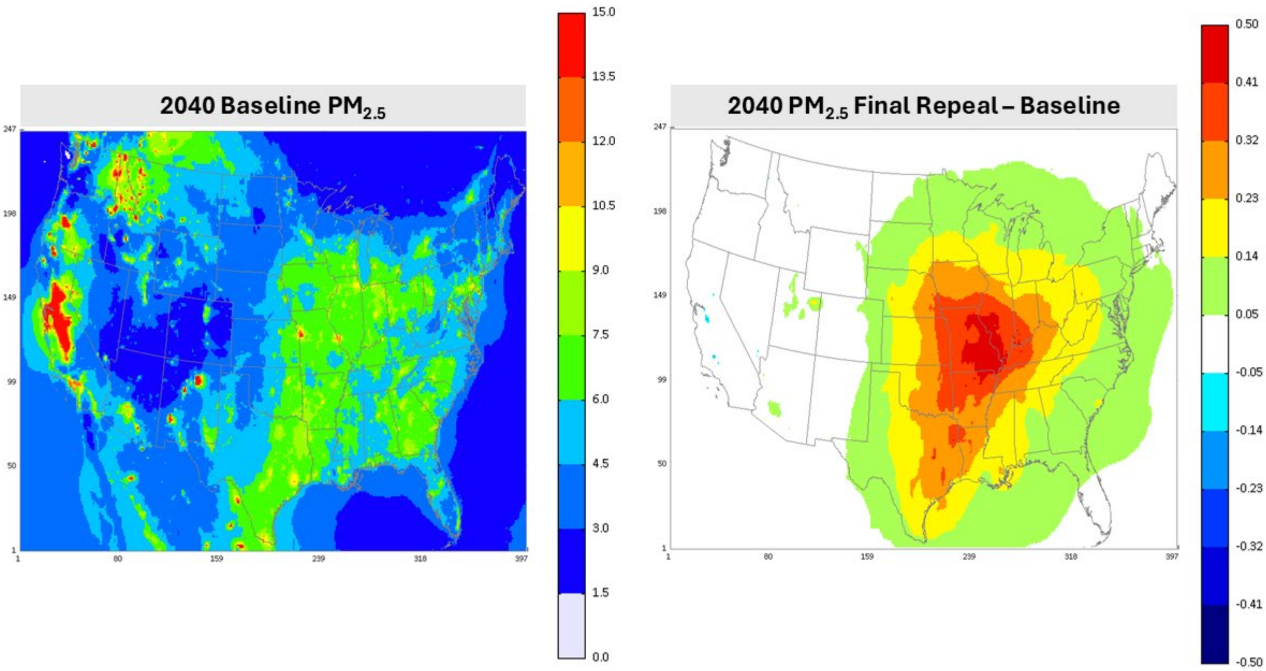

Figure A-13 Maps of PM2.5 in 2040. Baseline (with CPS) $PM_{2.5}$ concentrations (µg/m3) shown on the left. Change in $PM_{2.5}$ in the Final Repeal scenario compared to Baseline (with CPS) values (µg/m3) shown on the right.

Color bars for Figure A-11 differ in scale (±0.1 µg/m3) from color bars used in Figure A-12 through Figure A-14 (±0.5 µg/m3).

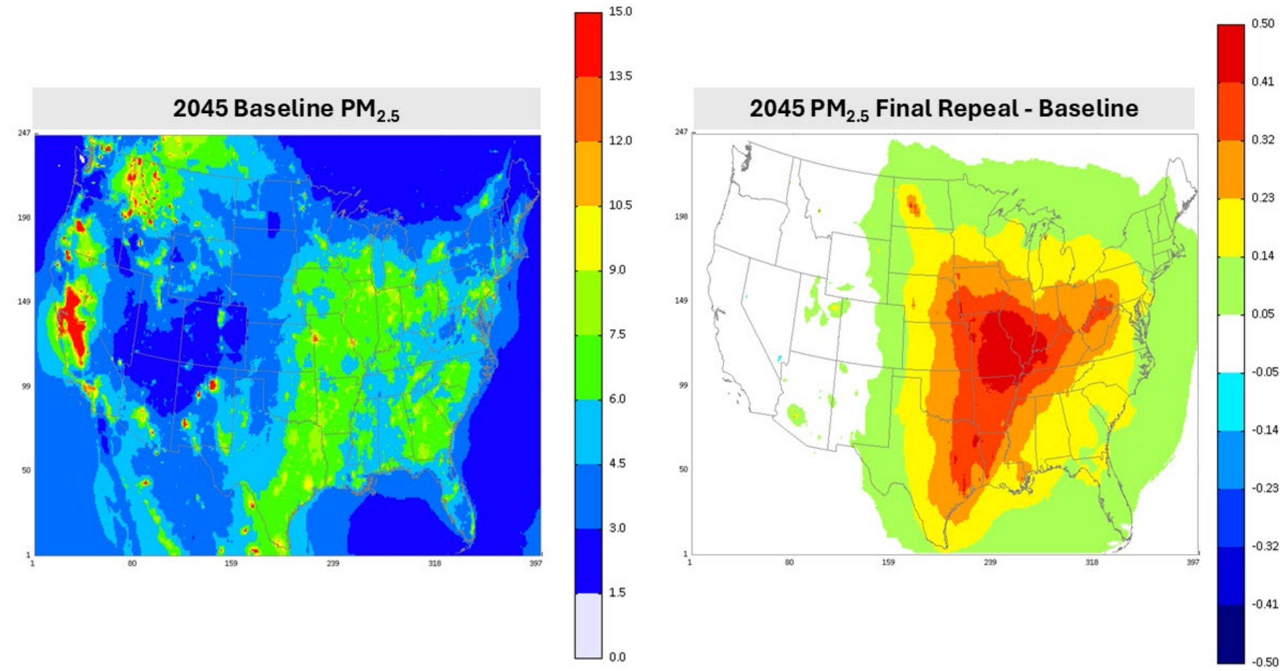

Figure A-14 Maps of PM2.5 in 2045. Baseline (with CPS) $PM_{2.5}$ concentrations (µg/m3) shown on the left. Change in $PM_{2.5}$ in the Final Repeal scenario compared to Baseline (with CPS) values (µg/m3) shown on the right.

Color bars for Figure A-11 differ in scale (±0.1 µg/m3) from color bars used in Figure A-12 through Figure A-14 (±0.5 µg/m3).

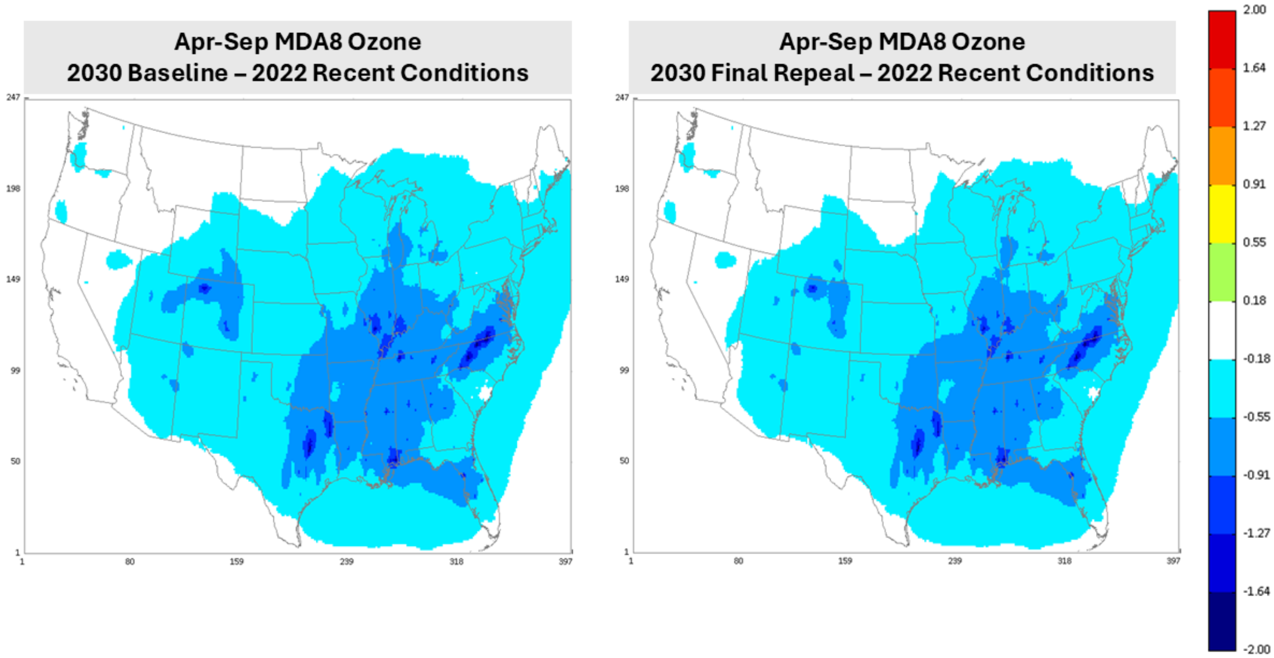

Figure A-15 Maps of changes in 2030 ASM-O3 from recent 2022 conditions. Baseline (with CPS) 2030 ozone concentrations compared to 2022 ozone concentrations (ppb) shown on left. 2030 Final Repeal scenario ozone concentrations compared to 2022 ozone concentrations (ppb) shown on right.

Color bars for Figure A-15 through Figure A-18 differ in scale (±2ppb) from color bars used in Figure A-7 through Figure A-10 (±0.2ppb).

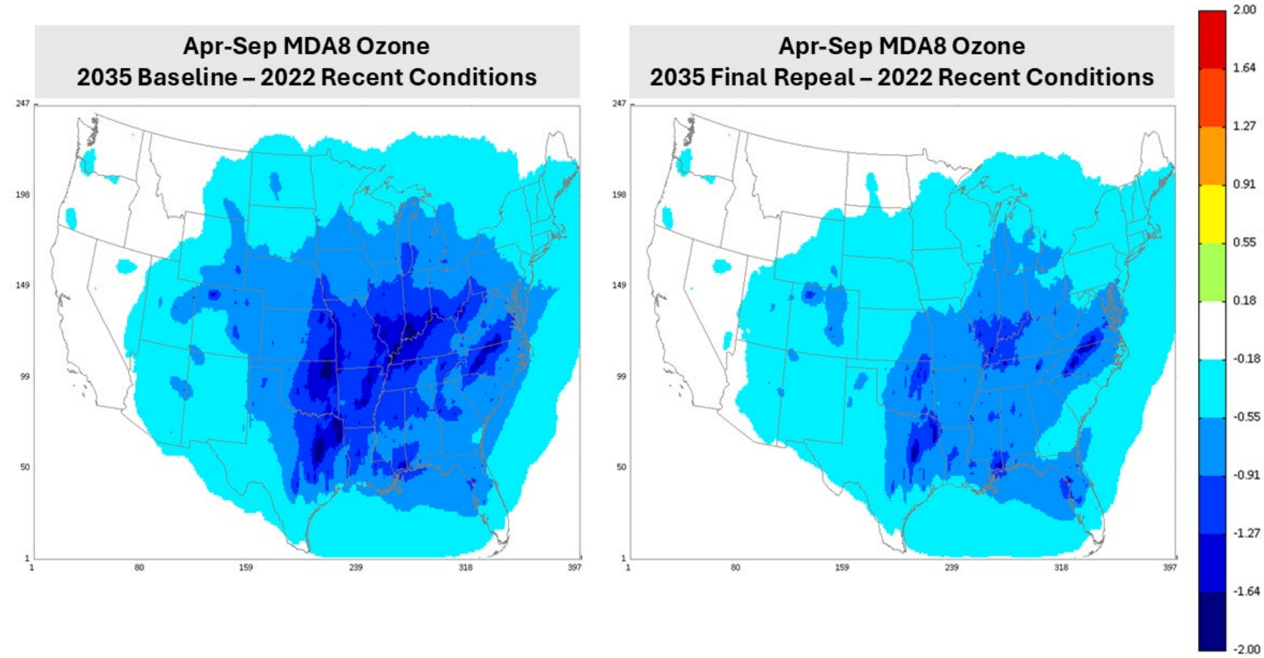

Figure A-16 Maps of changes in 2035 ASM-O3 from recent 2022 conditions. Baseline (with CPS) 2035 ozone concentrations compared to 2022 ozone concentrations (ppb) shown on left. 2035 Final Repeal scenario ozone concentrations compared to 2022 ozone concentrations (ppb) shown on right.

Color bars for Figure A-15 through Figure A-18 differ in scale (±2ppb) from color bars used in Figure A-7 through Figure A-10 (±0.2ppb).

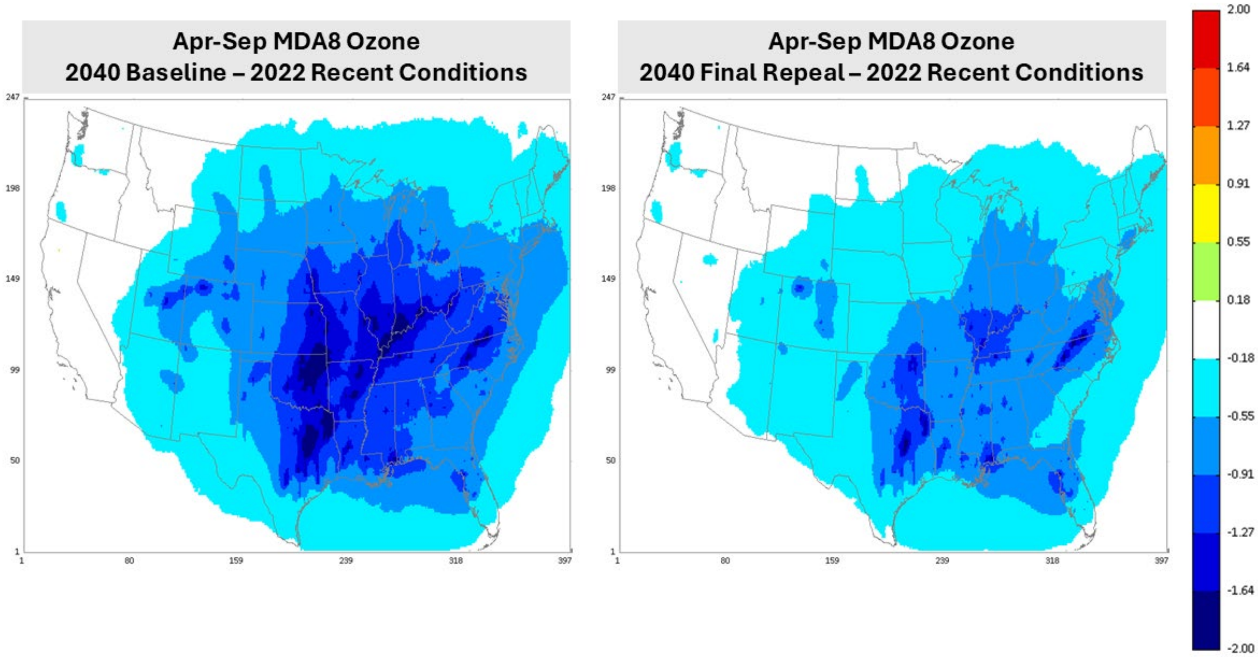

Figure A-17 Maps of changes in 2040 ASM-O3 from recent 2022 conditions. Baseline (with CPS) 2040 ozone concentrations compared to 2022 ozone concentrations (ppb) shown on left. 2040 Final Repeal scenario ozone concentrations compared to 2022 ozone concentrations (ppb) shown on right.

Color bars for Figure A-15 through Figure A-18 differ in scale (±2ppb) from color bars used in Figure A-7 through Figure A-10 (±0.2ppb).

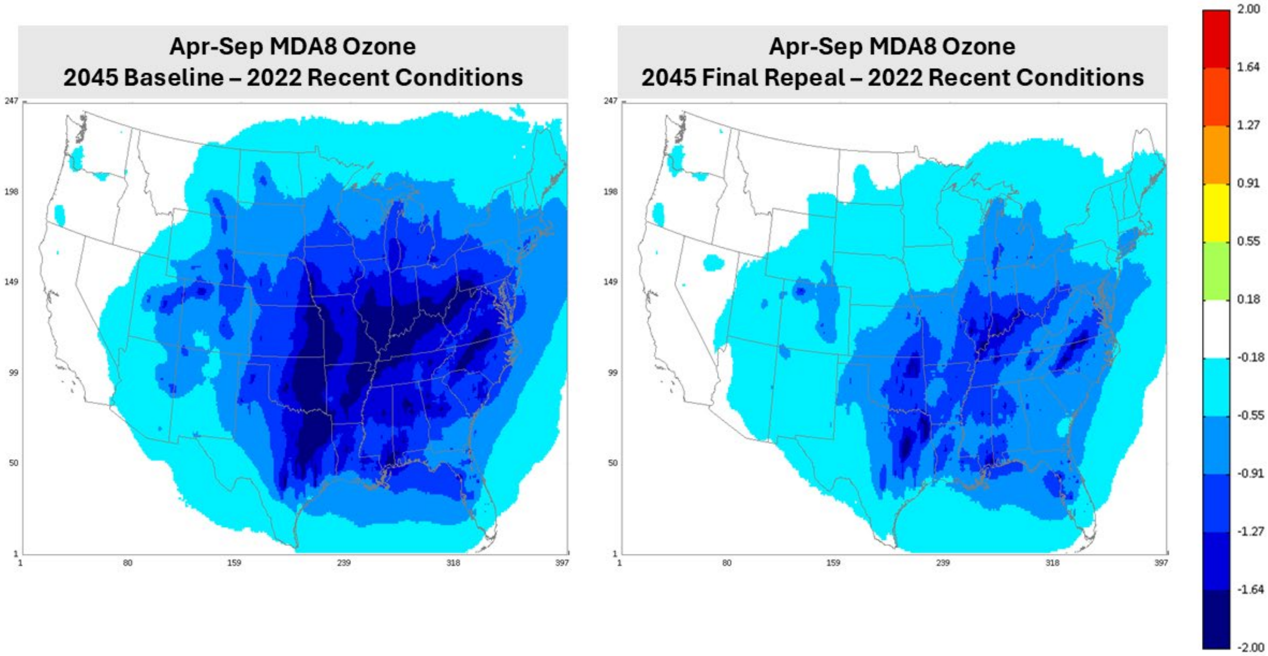

Figure A-18 Maps of changes in 2045 ASM-O3 from recent 2022 conditions. Baseline (with CPS) 2045 ozone concentrations compared to 2022 ozone concentrations (ppb) shown on left. 2045 Final Repeal scenario ozone concentrations compared to 2022 ozone concentrations (ppb) shown on right.

Color bars for Figure A-15 through Figure A-18 differ in scale (±2ppb) from color bars used in Figure A-7 through Figure A-10 (±0.2ppb).

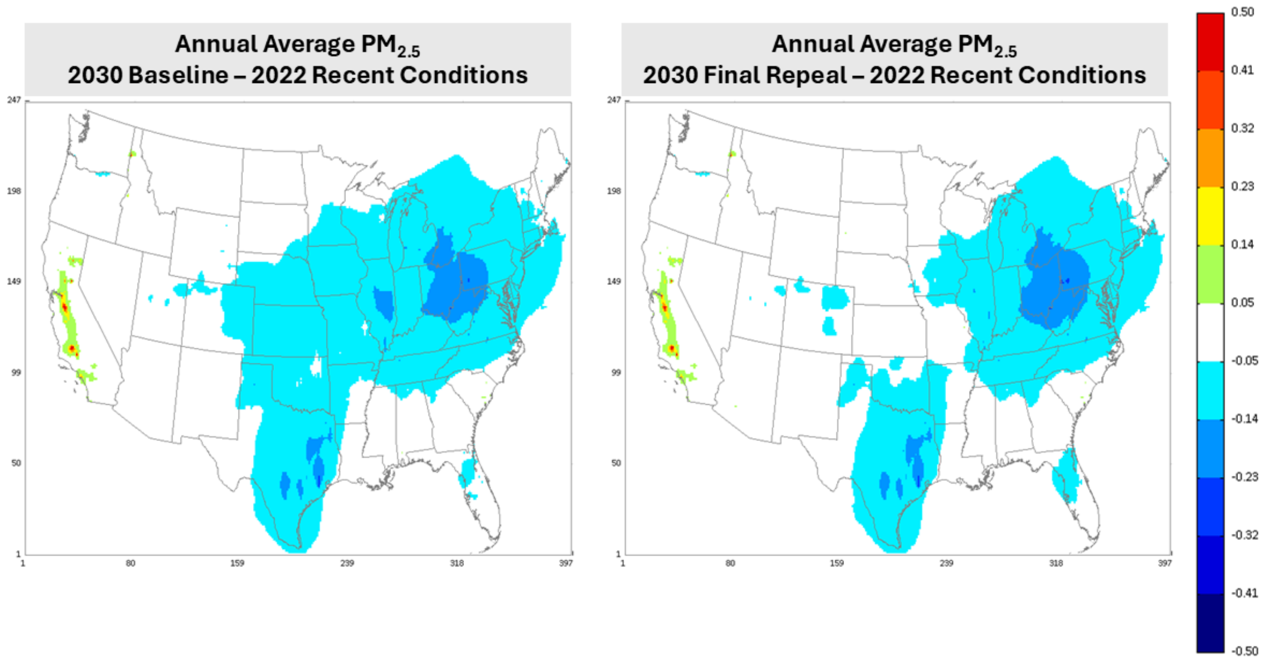

Figure A-19 Maps of changes in 2030 $PM_{2.5}$ from recent 2022 conditions. Baseline (with CPS) 2030 $PM_{2.5}$ concentrations compared to 2022 $PM_{2.5}$ concentrations (µg/m3) shown on left. 2030 Final Repeal scenario $PM_{2.5}$ concentrations compared to 2022 $PM_{2.5}$ concentrations (µg/m3) shown on right.

Color bars for Figure A-11 differ in scale (±0.1 µg/m3) from color bars used in this figure (±0.5 µg/m3).

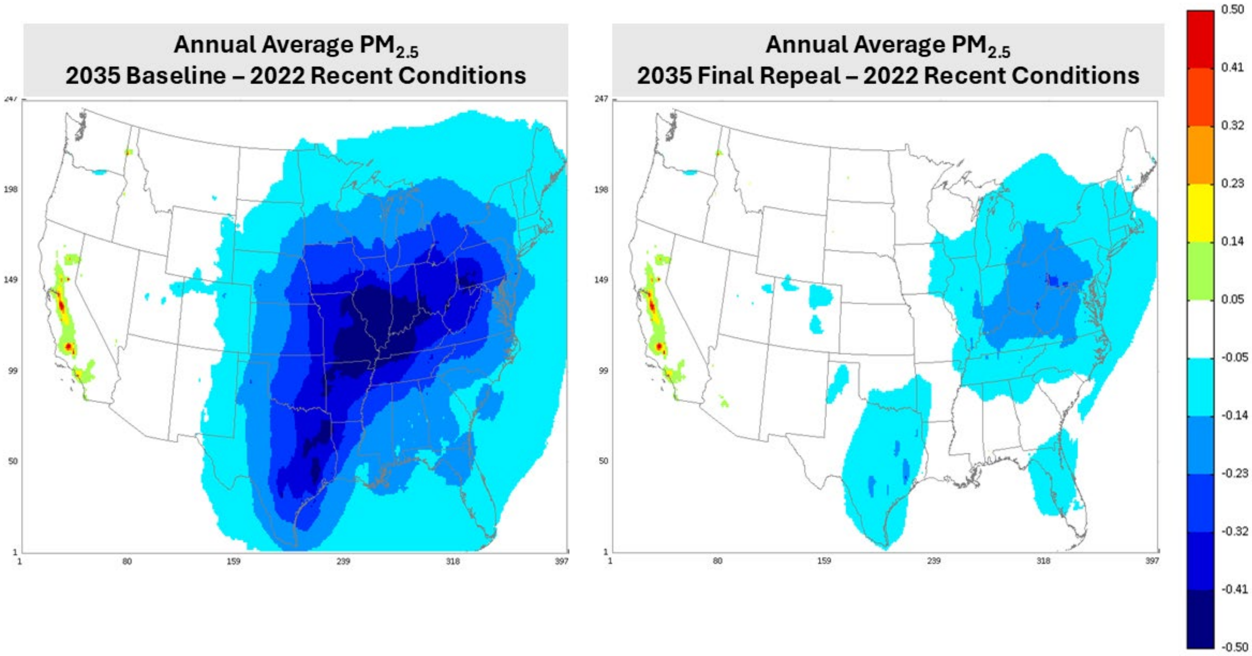

Figure A-20 Maps of changes in 2035 $PM_{2.5}$ from recent 2022 conditions. Baseline (with CPS) 2035 $PM_{2.5}$ concentrations compared to 2022 $PM_{2.5}$ concentrations (µg/m3) shown on left. 2035 Final Repeal scenario $PM_{2.5}$ concentrations compared to 2022 $PM_{2.5}$ concentrations (µg/m3) shown on right.

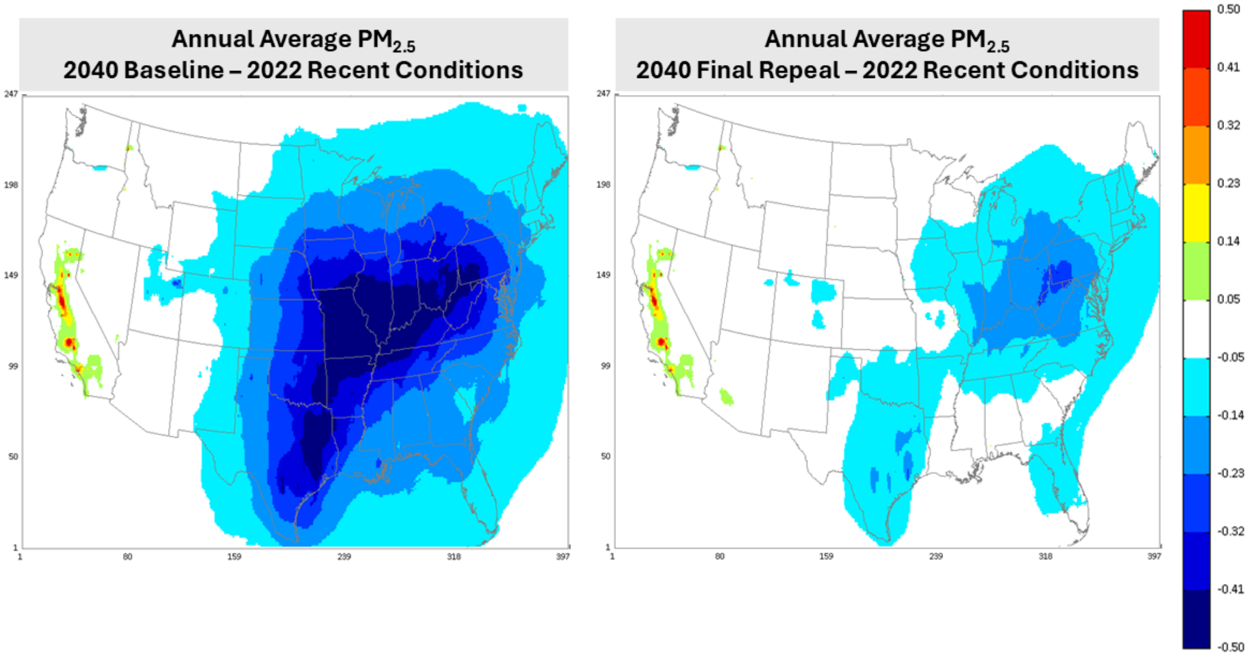

Figure A-21 Maps of changes in 2040 $PM_{2.5}$ from recent 2022 conditions. Baseline (with CPS) 2040 $PM_{2.5}$ concentrations compared to 2022 $PM_{2.5}$ concentrations (µg/m3) shown on left. 2040 Final Repeal scenario $PM_{2.5}$ concentrations compared to 2022 $PM_{2.5}$ concentrations (µg/m3) shown on right.

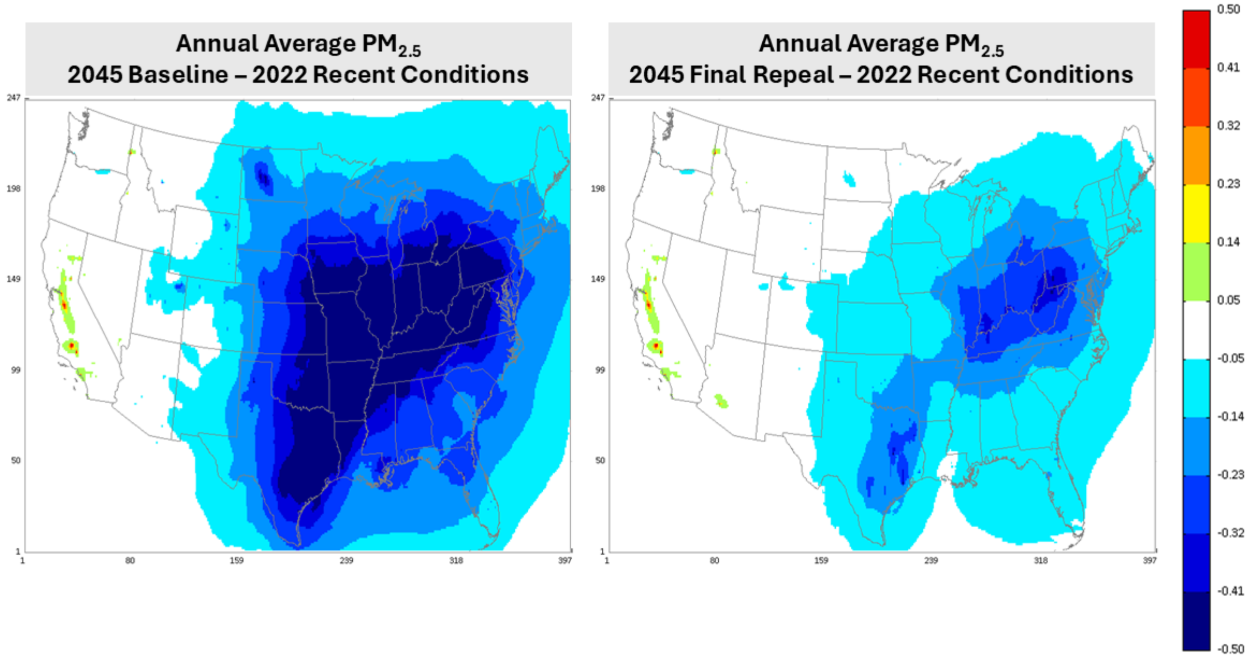

Figure A-22 Maps of changes in 2045 $PM_{2.5}$ from recent 2022 conditions. Baseline (with CPS) 2045 $PM_{2.5}$ concentrations compared to 2022 PM2.5 concentrations (µg/m3) shown on left. 2045 Final Repeal scenario $PM_{2.5}$ concentrations compared to 2022 $PM_{2.5}$ concentrations (µg/m3) shown on right.

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 (with CPS) or Final Repeal scenario 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 (with CPS) and for the Final Repeal scenarios, so any uncertainties associated with these assumptions is propagated through results for both the Baseline (with CPS) and Final Repeal scenarios in the same manner. In addition, emissions changes between the Baseline (with CPS) and Final Repeal scenarios are relatively small compared to modeled 2022 base year emissions that form the basis of the source apportionment approach described in this appendix. Previous studies have shown that air pollutant concentrations generally respond linearly to small emissions changes of up to 30 percent (Cohan et al., 2005; Cohan and Napelenok, 2011; Dunker et al., 2002; Koo et al., 2007;

Napelenok et al., 2006; Zavala et al., 2009). A second limitation is that the source apportionment contributions are informed by the spatial and temporal distribution of the emissions from each source tag as they occur in the 2022 base year modeled case. Thus, the contribution modeling results do not allow us to consider the effects of any changes to spatial distribution of EGU emissions within a state between the 2022 base year modeled case and the Baseline (with CPS) and Final Repeal scenarios analyzed in this RIA. Finally, the 2022 base year CAMx-modeled concentrations themselves have some uncertainty. While all models have some level of inherent uncertainty in their formulation and inputs, the 2002 base year model outputs have been evaluated against ambient measurements and have been shown to adequately reproduce spatially and temporally varying concentrations as described in the Air Quality Modeling Simulation Section (A.1). Additionally, the 2022 base year model outputs were fused with measured 2022 values to provide a gridded surface that closely matches measured values as described in the Applying Modeling Outputs to Create Spatial Fields Section (A.2).

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