Regulatory Impact Analysis for the Repeal of the Clean Power Plan, and the Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units

EPA-452/R-19-003
June 2019

Regulatory Impact Analysis for the Repeal of the Clean Power Plan, and the Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units

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EXECUTIVE SUMMARY

ES.1 Introduction

In this action, the U.S. Environmental Protection Agency (EPA) is finalizing three separate and distinct rulemakings. First, the EPA is repealing the Clean Power Plan (CPP) because the Agency has determined that the CPP exceeded the EPA's statutory authority under the Clean Air Act (CAA). Second, the EPA is finalizing the Affordable Clean Energy rule (ACE), consisting of Emission Guidelines for Greenhouse Gas (GHG) Emissions from Existing Electric Utility Generating Units (EGUs) under CAA section 111(d), that will inform states on the development, submittal, and implementation of state plans to establish performance standards for GHG emissions from certain fossil fuel-fired EGUs. In ACE, the Agency is finalizing its determination that heat rate improvement (HRI) is the best system of emission reduction (BSER) for reducing GHG—specifically carbon dioxide (CO_2)—emissions from existing coal-fired EGUs. Third, the EPA is finalizing new regulations for the EPA and state implementation of ACE and any future emission guidelines issued under CAA section 111(d).

This final action is an economically significant regulatory action that was submitted to the Office for Management and Budget (OMB) for interagency review. Any changes made in response to interagency review have been documented in the docket. This regulatory impact analysis (RIA) presents an assessment of the regulatory compliance costs and benefits associated with this action and is consistent with Executive Orders 12866, 13563, and 13771.

ES.2 Analysis

In this RIA, the Agency provides both an analysis of the repeal of the CPP and a full benefit-cost analysis of an illustrative policy scenario representing ACE, which models HRI at coal-fired EGUs.

For the analysis of the repeal of the CPP (described in Chapter 2), the EPA examines a number of lines of evidence including: several updated Integrated Planning Model (IPM) scenarios that consider different assumptions regarding implementation of the CPP (including that states are more likely to participate in interstate trading than previously considered and that because of the supreme court stay, even if the rule were to be implemented, it would be implemented on a significantly delayed time-frame), consideration of the changes the EPA (and others including the U.S. Energy Information Administration) have seen in CO_2 reductions across similar scenarios run over time, changing circumstances in the power sector (including fuel prices, technology changes and the age of different portions of the generating fleet) as well as commitments many power companies have made to significantly reduce CO_2 emissions. Based on this examination, the EPA concludes that even if the CPP were implemented, it would not achieve emission reductions beyond those that would be achieved in a business-as-usual projection.

For the ACE analysis, the illustrative policy scenario represents potential outcomes of state determinations of standards of performance, and compliance with those standards by affected coal-fired EGUs. ACE is being analyzed as a separate action that occurs only after repeal of the CPP, therefore the EPA is performing its analysis of ACE against a baseline without CPP (however as noted above, the EPA does not believe that there would be any significant differences between a scenario with or without CPP).

The analysis in this RIA relies on EPA's Power Sector Modeling Platform v6 using IPM. This accounts for changes in the power sector in recent years and projects our best understanding of important technological and economic trends into the future.

The EPA has identified the BSER to be HRI. In the final Emission Guidelines, the EPA is providing states with a list of candidate HRI technologies that must be evaluated when establishing standards of performance. The cost, suitability, and potential improvement for any of these HRI technologies depends on a range of unit-specific factors such as the size, age, fuel use, and the operating and maintenance history of the unit. As such, the HRI potential can vary significantly from unit to unit. The EPA does not have sufficient information to assess HRI potential on a unit-by-unit basis. CAA 111(d) also provides states with the responsibility to establish standards of performance and provides considerable flexibility in applying those emission standards. States may take source-specific factors into consideration – including the remaining useful life of the affected source – when applying the standards of performance. Generally, the EPA cannot sufficiently distinguish likely or representative standards of performance across individual affected units or groups of units and their compliance strategies.

Therefore, any analysis of the ACE rule must be illustrative. Nonetheless, the EPA believes that such illustrative analysis can provide important insights.

In this RIA, we evaluated an illustrative policy scenario representing the ACE rule that assumes HRI potential and costs will differ based on unit generating capacity and efficiency (i.e., heat rate). To establish categories of units and their assumed HRI potential for the illustrative policy scenario, we developed a methodology that is explained in Chapter 1. Affected sources were divided into twelve groups based on three size categories and four efficiency categories. A representative cost and performance assumption for HRI from the candidate technologies was identified for each grouping. The group-specific cost and performance assumptions were then applied to each unit in the group in the illustrative analysis. We then modeled the application of these assumptions in the power sector which provides a basis for the costs, emissions, and benefits analyses that illustrate the potential impacts of the final ACE rule.

We evaluated the potential impacts of the illustrative policy scenario using the present value (PV) of costs, benefits, and net benefits, calculated for the years 2023-2037 from the perspective of 2016, using both a three percent and seven percent end-of-period discount rate. In addition, the Agency presents the assessment of costs, benefits, and net benefits for specific snapshot years, consistent with historic practice. These snapshot years are 2025, 2030, and 2035.

The Agency believes that these specific years are each representative of several surrounding years, which enables the analysis of costs and benefits over the timeframe of 2025-2037. The year 2025 is an approximation for when the standards of performance under the final rule might be implemented, and the Agency estimates that monitoring, reporting, and recordkeeping (MR&R) costs may begin in 2023. Therefore, MR&R costs analysis is presented beginning in the year 2023, and full benefit-cost analysis is presented beginning in the year 2025. The analytical timeframe concludes in 2037, as this is the last year that may be represented with the analysis conducted for the specific year of 2035.

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

Table ES-1 provides the PV and equivalent annualized value (EAV) of costs, domestic climate benefits, ancillary health co-benefits, and net benefits of the illustrative policy scenario over the timeframe of 2023-2037. The EAV represents a flow of constant annual values that, had they occurred in each year from 2023 to 2037, would yield an equivalent present value. The EAV represents the value of a typical cost or benefit for each year of the analysis, in contrast to the year-specific estimates presented for the snapshot years of 2025, 2030, and 2035.

Table ES-1 Present Value and Equivalent Annualized Value of Compliance Costs, Domestic Climate Benefits, Ancillary Health Co-Benefits, and Net Benefits, Illustrative Policy Scenario, 3 and 7 Percent Discount Rates, 2023-2037 (millions of 2016$)

	Costs		Domestic Climate Benefits		Ancillary Health Co-Benefits		Net Benefits	
	3%	7%	3%	7%	3%	7%	3%	7%
Present Value	1,600	970	640	62	4,000 to 9,800	2,000 to 5,000	3,000 to 8,800	1,100 to 4,100
Equivalent Annualized Value	140	110	53	6.9	330 to 820	220 to 550	250 to 730	120 to 450

Notes: All estimates are rounded to two significant figures, so figures may not sum due to independent rounding. Climate benefits reflect the value of domestic impacts from CO_2 emissions changes.

Table ES-2 provides the PV and EAV of costs, benefits, and net benefits associated with the targeted pollutant, CO_2, over the timeframe of 2023-2037. This method of comparing costs to domestic climate benefits is consistent with how results were presented in the RIA for the ACE proposal. In this table, negative net benefits are indicated with parentheses.

Table ES-2 Present Value and Equivalent Annualized Value of Compliance Costs, Domestic Climate Benefits, and Net Benefits Associated with Targeted Pollutant (CO_2), Illustrative Policy Scenario, 3 and 7 Percent Discount Rates, 2023-2037 (millions of 2016$)

	Costs		Domestic Climate Benefits		Net Benefits associated with the Targeted Pollutant (CO_2)	
	3%	**7%**	**3%**	**7%**	**3%**	**7%**
Present Value	1,600	970	640	62	(980)	(910)
Equivalent Annualized Value	140	110	53	6.9	(82)	(100)

Notes: Negative net benefits indicate forgone net benefits. All estimates are rounded to two significant figures, so figures may not sum due to independent rounding. Climate benefits reflect the value of domestic impacts from CO_2 emissions changes. This table does not include estimates of ancillary health co-benefits from changes in electricity sector SO_2 and NO_X emissions.

ES.3 Compliance Costs

The power industry's "compliance costs" are represented in this analysis as the change in electric power generation costs between the baseline and the illustrative policy scenario, including the cost of monitoring, reporting, and recordkeeping (MR&R). In simple terms, these costs are an estimate of the additional power industry expenditures required to comply with the final action, as represented by the illustrative policy scenario, minus the power generation costs in the baseline. Table ES-3 presents the annualized compliance costs of the illustrative policy scenario.[1] The EPA uses the projection of private compliance costs as an estimate of the total social cost, which is the appropriate metric for formal economic welfare analysis, of this final action.

Table ES-3 Compliance Costs of Illustrative Policy Scenario in 2025, 2030, and 2035 (millions of 2016$)

Year	Cost
2025	290
2030	280
2035	25

Notes: Compliance costs equal the projected change in total power sector generating costs, plus the costs of monitoring, reporting, and recordkeeping. All estimates are rounded to two significant figures.

[1] This RIA does not identify who ultimately bears the compliance costs, such as owners of generating assets through changes in their profits or electricity consumers through changes in their bills, although the potential impacts on consumers and producers are described in Chapter 5.

ES.4 Emissions Changes

Emissions are projected to be lower under the illustrative policy scenario than under the baseline, as shown in Table ES-4 and Table ES-5. Table ES-4 shows projected aggregate CO_2 emissions relative to the baseline.

Table ES-4 Projected CO_2 Emission Impacts of Illustrative Policy Scenario, Relative to Baseline in 2025, 2030, and 2035

	CO_2 Emissions (MM Short Tons)			CO_2 Emissions Change (MM Short Tons)			CO_2 Emissions Change Percent Change		
	2025	2030	2035	2025	2030	2035	2025	2030	2035
Baseline	1,774	1,743	1,719	-	-	-	-	-	-
Illustrative Policy Scenario	1,762	1,732	1,709	(12)	(11)	(9.3)	(0.7%)	(0.7%)	(0.5%)

Table ES-5 shows projected aggregate emissions relative to the baseline for sulfur dioxide (SO_2) and nitrogen oxides (NO_X), and mercury (Hg) from the electricity sector.

Table ES-5 Projected SO_2, NO_X, and Hg Electricity Sector Emissions of Illustrative Policy Scenario in 2025, 2030, and 2035

	Baseline	Illustrative Policy Scenario	Emissions Change	Percent Change from Baseline
SO_2 (thousand tons)				
2025	912.6	908.5	(4.1)	(0.4%)
2030	885.6	879.9	(5.7)	(0.6%)
2035	817.0	810.6	(6.4)	(0.8%)
NO_X (thousand tons)				
2025	844.4	837.1	(7.3)	(0.9%)
2030	810.1	803.0	(7.1)	(0.9%)
2035	752.8	746.8	(6.0)	(0.8%)
$PM_{2.5}$ (thousand tons)				
2025	108.7	108.1	(0.6)	(0.6%)
2030	110.1	109.7	(0.4)	(0.4%)
2035	113.0	112.3	(0.7)	(0.6%)
Hg (tons)				
2025	4.7	4.7	(0.03)	(0.7%)
2030	4.5	4.4	(0.03)	(0.7%)
2035	4.0	4.0	(0.03)	(0.6%)

Source: Integrated Planning Model, 2018.
Notes: SO_2, and NO_X reductions are used for estimating the health benefits from reduced particulate matter and ozone exposures. The SO_2 and NO_X emissions are direct outputs from the IPM simulations as reported in Chapter 3; however, the $PM_{2.5}$ emissions were derived based on IPM-predicted heat rate and other factors as described in Chapter 8.

ES.5 Climate and Health Co-Benefits

We estimated climate-related impacts from changes in CO_2 and the air quality-related impacts from changes in SO_2 and NO_X. We refer to climate benefits as “targeted pollutant benefits” because these are the direct benefits of reducing CO_2. We refer to air pollution health benefits as ancillary “co-benefits” because they result from policies affecting CO_2 but are not the goal of this policy. To estimate the climate benefits associated with changes in CO_2 emissions, we apply a measure of the domestic social cost of carbon (SC-CO_2). The SC-CO_2 is a metric that estimates the monetary value of impacts associated with marginal changes in CO_2 emissions in each year. The SC-CO_2 estimates used in this RIA account for the direct impacts of climate change that are anticipated to occur within the United States. As discussed in Chapters 4.3 and 7, the estimated domestic climate benefits presented for this rule are based on evolving methodologies and depend in important respects on assumptions that are uncertain and subject to further revision with improvements in the science and modeling of climate change impacts.

We performed gridded photochemical air quality modeling to support the air quality benefits assessment of the ACE rule and quantified the health benefits attributable to changes in fine particles 2.5 microns and smaller ($PM_{2.5}$) and ground-level ozone. This modeling accounted for the current suite of local, state and federal policies expected to reduce $PM_{2.5}$ and $PM_{2.5}$ precursor emissions in future years.[2] Table ES-6 reports the combined domestic climate benefits and ancillary health co-benefits attributable to changes in SO_2 and NO_X emissions, discounted at three percent and seven percent and presented in 2016 dollars, in the years 2025, 2030 and 2035. This table reports the air pollution effects calculated using $PM_{2.5}$ log-linear concentration-response functions that quantify risk associated with the full range of $PM_{2.5}$ exposures experienced by the population (U.S. EPA, 2009; U.S. EPA, 2011; NRC, 2002).[3] Nearly all the $PM_{2.5}$-related benefits reported for each year occur in locations where the annual mean $PM_{2.5}$ concentrations are projected to be below the annual $PM_{2.5}$ standard of 12 $\mu g/m^3$.

In general, we are more confident in the size of the risks we estimate from simulated $PM_{2.5}$ concentrations that coincide with the bulk of the observed PM concentrations in the epidemiological studies that are used to estimate the benefits. Likewise, we are less confident in the risk we estimate from simulated $PM_{2.5}$ concentrations that fall below the bulk of the observed data in these studies.[4] Furthermore, when setting the 2012 PM NAAQS, the Administrator acknowledged greater uncertainty in specifying the "magnitude and significance" of PM-related health risks at PM concentrations below the NAAQS. As noted in the preamble to the 2012 PM

[2] Policies expected to impact EGU sector emissions are accounted for out to 2025, 2030, and 2035 future years, but policies expected to impact other emissions source sectors are only accounted for out to 2023.
[3] This approach is consistent with employing a no-threshold assumption for estimating $PM_{2.5}$-related health effects. The preamble to the 2012 PM NAAQS noted that "[a]s both the EPA and CASAC recognize, in the absence of a discernible threshold, health effects may occur over the full range of concentrations observed in the epidemiological studies." (78 FR 3149, 15 January 2013). This log-linear, no-threshold approach to calculating, valuing and reporting the avoided number of $PM_{2.5}$-attributable deaths is consistent with recent RIAs (U.S. EPA 2009b, 2010c, 2010d, 2011a, 2011b, 2011c, 2012, 2013, 2014, 2015a, 2016).
[4] The Federal Register Notice for the 2012 PM NAAQS indicates that "[i]n considering this additional population level information, the Administrator recognizes that, in general, the confidence in the magnitude and significance of an association identified in a study is strongest at and around the long-term mean concentration for the air quality distribution, as this represents the part of the distribution in which the data in any given study are generally most concentrated. She also recognizes that the degree of confidence decreases as one moves towards the lower part of the distribution."

NAAQS final rule, in the context of selecting and alternative NAAQS, the "EPA concludes that it is not appropriate to place as much confidence in the magnitude and significance of the associations over the lower percentiles of the distribution in each study as at and around the long-term mean concentration." (78 FR 3154, 15 January 2013).

To give readers insight to the uncertainty in the estimated $PM_{2.5}$ mortality benefits occurring at lower ambient levels, we also report the PM benefits excluding benefits below certain $PM_{2.5}$ concentration cut-points and concentration-response parameters. The percentage of estimated $PM_{2.5}$-related premature deaths occurring below the lowest measured levels (LML) of the two long-term epidemiological studies we use to estimate risk varies between 5 percent (Krewski et al. 2009) and 69 percent (Lepeule et al. 2012). The percentage of estimated premature deaths occurring above the LML and below the NAAQS ranges between 94 percent (Krewski et al. 2009) and 31 percent (Lepeule et al. 2012). Less than one percent of the estimated premature deaths occur above the annual mean $PM_{2.5}$ NAAQS of 12 $\mu g/m^3$. Estimates of ancillary co-benefits excluding those below the LML and the NAAQS are provided in Chapter 4 and, along with climate benefits, are compared to costs in Chapter 6.

Table ES-6 reports the benefits to society for the illustrative policy scenario.

Table ES-6 Monetized Benefits of Illustrative Policy Scenario in 2025, 2030, and 2035 (millions of 2016$)

	Discounted at 3%			Discounted at 7%		
	Domestic Climate Benefits	**Ancillary Health Co-Benefits**	**Total Benefits**	**Domestic Climate Benefits**	**Ancillary Health Co-Benefits**	**Total Benefits**
2025	81	390 to 970	470 to 1,000	13	360 to 900	370 to 920
2030	81	490 to 1,200	570 to 1,300	14	460 to 1,100	470 to 1,100
2035	72	550 to 1,400	620 to 1,400	13	510 to 1,300	520 to 1,300

Notes: All estimates are rounded to two significant figures, so figures may not sum due to independent rounding. Climate benefits reflect the value of domestic impacts from CO_2 emissions changes. The ancillary health co-benefits reflect the sum of the $PM_{2.5}$ and ozone benefits from changes in electricity sector $PM_{2.5}$, SO_2 and NO_X emissions and reflect the range based on adult mortality functions (e.g., from Krewski *et al.* (2009) with Smith *et al.* (2009) to Lepeule *et al.* (2012) with Jerrett et al. (2009))

ES.6 Net Benefits

In the decision-making process it is useful to consider the change in benefits due to the targeted pollutant relative to the costs. Therefore, in Chapter 6 we present a comparison of the benefits from the targeted pollutant – CO_2 – with the compliance costs.[5] Excluded from this comparison are the co-benefits from changes in $PM_{2.5}$ and ozone concentrations from changes in SO_2 and NO_X, emissions that are projected to accompany changes in CO_2 emissions.[6]

Table ES-7 presents the PV and EAV of the estimated costs, benefits, and net benefits associated with the targeted pollutant, CO_2, for the timeframe of 2023-2037, relative to the baseline. In Table ES-7, and all net benefit tables, negative net benefits are indicated with parentheses.

Table ES-7 Present Value and Equivalent Annualized Value of Compliance Costs, Climate Benefits, and Net Benefits Associated with Targeted Pollutant (CO_2), Illustrative Policy Scenario, 3 and 7 Percent Discount Rates, 2023-2037 (millions of 2016$)

	Costs		Domestic Climate Benefits		Net Benefits associated with the Targeted Pollutant (CO_2)	
	3%	**7%**	**3%**	**7%**	**3%**	**7%**
Present Value	1,600	970	640	62	(980)	(910)
Equivalent Annualized Value	140	110	53	6.9	(82)	(100)

Notes: Negative net benefits indicate forgone net benefits. All estimates are rounded to two significant figures, so figures may not sum due to independent rounding. Climate benefits reflect the value of domestic impacts from CO_2 emissions changes. This table does not include estimates of ancillary health co-benefits from changes in electricity sector $PM_{2.5}$, SO_2 and NO_X emissions.

Table ES-8 presents the costs, benefits, and net benefits associated with the targeted pollutant for the specific snapshot years.

[5] While the benefits are limited to the targeted pollutant, the cost as discussed above is the change in generation cost for the entire power sector plus MR&R costs. The cost reported in Table ES-7 is not limited solely to those costs that occur at the sources regulated by this final action.

[6] When considering whether a regulatory action is a potential welfare improvement (i.e., potential Pareto improvement) it is necessary to consider all impacts of the action.

Table ES-8 Compliance Costs, Climate Benefits, and Net Benefits Associated with Targeted Pollutant (CO_2) in 2025, 2030, and 2035, Illustrative Policy Scenario, 3 and 7 Percent Discount Rates (millions of 2016$)

	Costs		Domestic Climate Benefits		Net Benefits associated with the Targeted Pollutant (CO_2)	
	3%	**7%**	**3%**	**7%**	**3%**	**7%**
2025	290	290	81	13	(210)	(280)
2030	280	280	81	14	(200)	(260)
2035	25	25	72	13	47	(11)

Notes: Negative net benefits indicate forgone net benefits. All estimates are rounded to two significant figures, so figures may not sum due to independent rounding. Climate benefits reflect the value of domestic impacts from CO_2 emissions changes. This table does not include estimates of ancillary health co-benefits from changes in electricity sector $PM_{2.5}$, SO_2 and NO_X emissions.

Table ES-9 and Table ES-10 provide the estimated costs, benefits, and net benefits, inclusive of the ancillary health-co benefits. Table ES-9 presents the PV and EAV estimates, and Table ES-10 presents the estimates for the specific years of 2025, 2030, and 2035.

Table ES-9 Present Value and Equivalent Annualized Value of Compliance Costs, Total Benefits, and Net Benefits, 2023-2037, Illustrative Policy Scenario, 3 and 7 Percent Discount Rates (millions of 2016$)

	Costs		Benefits		Net Benefits	
	3%	**7%**	**3%**	**7%**	**3%**	**7%**
Present Value	1,600	970	4,600 to 10,000	2,100 to 5,000	3,000 to 8,800	1,100 to 4,100
Equivalent Annualized Value	140	110	390 to 870	230 to 550	250 to 730	120 to 450

Notes: All estimates are rounded to two significant figures, so figures may not sum due to independent rounding. Total benefits include both climate benefits and ancillary health co-benefits. Climate benefits reflect the value of domestic impacts from CO_2 emissions changes. The ancillary health co-benefits reflect the sum of the $PM_{2.5}$ and ozone benefits from changes in electricity sector $PM_{2.5}$, SO_2 and NO_X emissions and reflect the range based on adult $PM_{2.5}$ and ozone mortality functions (i.e., from Krewski *et al.* (2009) with Smith *et al.* (2009) to Lepeule *et al.* (2012) with Jerrett et al. (2009)).

Table ES-10 Compliance Costs, Total Benefits, and Net Benefits in 2025, 2030, and 2035, Illustrative Policy Scenario, 3 and 7 Percent Discount Rates (millions of 2016$)

	Costs		Benefits		Net Benefits	
	3%	7%	3%	7%	3%	7%
2025	290	290	470 to 1,000	370 to 920	180 to 760	84 to 630
2030	280	280	570 to 1,300	470 to 1,100	300 to 1,000	200 to 860
2035	25	25	620 to 1,400	520 to 1,300	600 to 1,400	500 to 1,200

Notes: All estimates are rounded to two significant figures, so figures may not sum due to independent rounding. Total benefits include both climate benefits and ancillary health co-benefits. Climate benefits reflect the value of domestic impacts from CO_2 emissions changes. The ancillary health co-benefits reflect the sum of the $PM_{2.5}$ and ozone benefits from changes in electricity sector $PM_{2.5}$, SO_2 and NO_X emissions and reflect the range based on adult $PM_{2.5}$ and ozone mortality functions (i.e., from Krewski *et al.* (2009) with Smith *et al.* (2009) to Lepeule *et al.* (2012) with Jerrett et al. (2009)).

The EPA typically reports the cost of a rule as the net change in production expenditures by affected sources as they find the least costly way of complying with the rule (including costs to states to implement the rule). Changes in compliance costs may arise from net changes in capital, labor, intermediate inputs, and resources, including fuel, expenses. If prices in related markets do not change, the sum of these expenditures approximate social cost of the rule to the extent prices of goods reflect their social opportunity cost. The net change in these expenditures are borne by consumers and producers as a result of the rule. An alternative presentation of benefits and costs is to report the change in expenditures on fuels as a benefit, and not as a cost, regardless of the sign of the change in expenditures on fuels. This accounting approach is consistent with OMB accounting which is to account for changes in fuel expenditures as a benefit.

Table ES-11 shows benefits, costs and net benefits where the change in expenditures on fuels in the illustrative policy scenario is reported as a benefit, and not as a cost. The net-benefits of the illustrative policy scenario do not change with this alternative presentation. The change in the fuel expenditures include overall net reductions in expenditures on coal (resulting from reduced coal use at the affected sources and projected increases and decreases in delivered coal prices) as well as the net increases and decreases in the expenditures on other fuels in the electricity sector (e.g., natural gas and uranium) as the sector responds in equilibrium. The costs are the net changes in expenditures on capital, and fixed and variable O&M, some of which are positive and some negative changes depending on the year, as well as MR&R costs. See Table 3-7 for a detailed breakdown of production costs, including fuel costs.

Table ES-11 Alternative Net Benefits Presentation: Present Value and Equivalent Annualized Value of Compliance Costs, Total Benefits, and Net Benefits, 2023-2037, Illustrative Policy Scenario, 3 and 7 Percent Discount Rates, (millions of 2016$)

	Costs		**Benefits**		**Net Benefits**	
	3%	**7%**	**3%**	**7%**	**3%**	**7%**
Present Value	4,700	2,700	7,700 to 13,000	3,800 to 6,700	3,000 to 8,800	1,100 to 4,100
Equivalent Annualized Value	400	290	650 to 1,100	410 to 740	250 to 730	120 to 450

Notes: All estimates are rounded to two significant figures, so figures may not sum due to independent rounding. This table shows benefits, costs and net benefits where the change in expenditures on fuels in the illustrative policy scenario is reported as a benefit, and not as a cost. Total benefits include climate benefits, ancillary health co-benefits, and change in expenditures on fuels. Climate benefits reflect the value of domestic impacts from CO_2 emissions changes. The ancillary health co-benefits reflect the sum of the $PM_{2.5}$ and ozone benefits from changes in electricity sector $PM_{2.5}$, SO_2 and NO_X emissions and reflect the range based on adult $PM_{2.5}$ and ozone mortality functions (i.e., from Krewski *et al.* (2009) with Smith *et al.* (2009) to Lepeule *et al.* (2012) with Jerrett et al. (2009)).

ES.7 Economic and Employment Impacts

This final action has energy market implications. Environmental regulation may affect groups of workers differently, as changes in abatement and other compliance activities cause labor and other resources to shift. An employment impact analysis describes the characteristics of groups of workers potentially affected by a regulation, as well as labor market conditions in affected occupations, industries, and geographic areas. Market and employment impacts of this final action are discussed in Chapter 5 of this RIA.

ES.8 Limitations and Uncertainty

Throughout this RIA we consider a number of sources of uncertainty, both quantitatively and qualitatively. We also summarize other potential sources of benefits and costs that may result from this final action that have not been quantified or monetized. We did not account for certain benefits and costs including certain omitted benefits and costs from changes in CO_2, SO_2, NO_X and direct $PM_{2.5}$, emissions from the electricity sector, from changes in other pollutants within and outside the electricity sector, and effects outside of the electricity market. These limitations, including where possible how they directly may affect estimated benefits and costs, are summarized below and discussed in more detail throughout the RIA.

There are important impacts that the EPA could not monetize. Due to current data and modeling limitations, our estimates of the benefit impacts from reducing CO_2 emissions do not include important impacts like ocean acidification or potential tipping points in natural or managed ecosystems. Ancillary benefits from changing direct exposure to SO_2, NO_X, as well as ecosystem changes and visibility impairment, from changes in these pollutants are also omitted.

Changes in the health and ecosystems from changes in mercury from the electricity sector are not monetized, although increases in mercury emissions are reported in Chapter 3. Potential changes in other air and water emissions from the electricity sector, including hazardous air pollutants (e.g., hydrochloric acid) and their associated effects on heath, ecosystems, and visibility are not quantified. Potential changes in emissions from producing fuels, such as methane from coal and gas production, are also unaccounted for.

The compliance costs reported in this RIA are not social costs, although in this analysis we use compliance costs as a proxy for social costs. Changes in costs and benefits due to changes in economic welfare of suppliers to the electricity market, including workers in the electricity market and in related markets, and non-electricity consumers from those suppliers (net of transfers), such as industrial consumers of fossil fuels, are not accounted for. Furthermore, costs due to interactions with pre-existing market distortions outside the electricity sector are omitted.

Key uncertainties that affect the estimates of benefits and costs of this final regulation include those that affect costs and emissions from the electricity sector. There is uncertainty in the availability and cost of the candidate HRI technologies at affected coal-fired EGUs on a unit-by-unit basis, and the illustrative policy scenario makes assumptions about the availability and cost of HRI across and within groups of units with similar generating capacity and heat rates. Furthermore, in the illustrative policy scenario HRI are imposed on units to represent the effect of potential standards of performance, but the required standards of performance are not represented in the electricity model directly. Affected sources may have certain flexibilities in how they comply with the standards of performance that differ from the technologies used to determine the sources' standards of performance, but this possibility is not captured in the illustrative policy scenario. In addition, there is uncertainty in future economic conditions that could affect fuel supplies, technology costs, and electricity demand in the electricity sector.

The estimated health benefits from changes in $PM_{2.5}$ and ozone concentrations are subject to uncertainties related to: (1) the projected future $PM_{2.5}$ and ozone concentrations; and, (2) the relationship between air quality changes and health outcomes. For the first uncertainty, which is discussed in more detail in Chapter 8, we are more confident in the estimated change in annual mean $PM_{2.5}$ concentrations than we are in the estimated absolute $PM_{2.5}$ levels. Consequently, we are more confident in the estimated total benefits than in sensitivity estimates of benefits over specific concentration ranges as described in Chapter 4. We address the second uncertainty in part by quantifying benefits using a range of adult mortality concentration-response relationships (e.g., from Krewski et al. (2009) with Smith et al. (2009) to Lepeule et al. (2012) with Jerrett et al. (2009)). The $PM_{2.5}$ concentration-response models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type.[7] Furthermore, as discussed above, there is greater uncertainty in the effects of exposure at low $PM_{2.5}$ levels.

This RIA does not evaluate whether or not there will be any changes in PM attainment status. However, there are few areas whose attainment status may be affected.[8] The extent to which the monetized health co-benefits and costs reported in this RIA are overestimated or underestimated partially depends on a variety of federal and state decisions with respect to NAAQS implementation and compliance, including Prevention of Significant Deterioration (PSD) requirements.

[7] More information on potential uncertainties and assumptions for $PM_{2.5}$ benefits is available in OMB's 2017 Draft Report to Congress on the Benefits and Costs of Federal Regulations and Agency Compliance with the Unfunded Mandates Reform Act, pg. 13 – 18.

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CHAPTER 1: INTRODUCTION AND BACKGROUND

1.1 Introduction

In this action, the U.S. Environmental Protection Agency (EPA) is finalizing three separate and distinct rulemakings. First, the EPA is repealing the Clean Power Plan (CPP) because the Agency has determined that the CPP exceeded the EPA's statutory authority under the Clean Air Act (CAA). Second, the EPA is finalizing the Affordable Clean Energy rule (ACE), consisting of Emission Guidelines for Greenhouse Gas (GHG) Emissions from Existing Electric Utility Generating Units (EGUs) under CAA section 111(d), that will inform states on the development, submittal, and implementation of state plans to establish performance standards for GHG emissions from certain fossil fuel-fired EGUs. In ACE, the Agency is finalizing its determination that heat rate improvement (HRI) is the best system of emission reduction (BSER) for reducing GHG—specifically carbon dioxide (CO_2)—emissions from existing coal-fired EGUs. Third, the EPA is finalizing new regulations for the EPA and state implementation of ACE and any future emission guidelines issued under CAA section 111(d).

In this RIA, the Agency provides both an analysis of the repeal of the CPP and a full benefit-cost analysis of an illustrative policy scenario representing ACE, which models HRI at coal-fired EGUs.

This chapter contains background information on this rule, an overview of the regulatory impact analysis conducted and scenario analyzed, as well as an outline of the chapters in this report. The EPA's analysis in Chapter 2 satisfies any need for regulatory impact analysis that may be required by statute or executive order for the repeal of the CPP.

1.2 Legal and Economic Basis for this Rulemaking

1.2.1 Statutory Requirement

Clean Air Act section 111, which Congress enacted as part of the 1970 Clean Air Act Amendments, establishes mechanisms for controlling emissions of air pollutants from stationary sources. This provision requires the EPA to promulgate a list of categories of stationary sources that the Administrator, in his or her judgment, finds "causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare."[1] The EPA has listed more than 60 stationary source categories under this provision.[2] Once the EPA lists a source category, the EPA must, under CAA section 111(b)(1)(B), establish "standards of performance" for emissions of air pollutants from new sources in the source categories.[3] These standards are known as new source performance standards (NSPS), and they are national requirements that apply directly to the sources subject to them.

When the EPA establishes NSPS for sources in a source category under CAA section 111(b), the EPA is also required, under CAA section 111(d)(1), to prescribe regulations for states to submit plans regulating existing sources in that source category for any air pollutant that, in general, is not regulated under the CAA section 109 requirements for the NAAQS or regulated under the CAA section 112 requirements for hazardous air pollutants (HAP). CAA section 111(d)'s mechanism for regulating existing sources differs from the one that CAA section 111(b) provides for new sources because CAA section 111(d) contemplates states submitting plans that establish "standards of performance" for the affected sources and that contain other measures to implement and enforce those standards.

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

Under CAA section 111(d), a state must submit its plan to the EPA for approval, and the EPA must approve the state plan if it is "satisfactory."[4] If a state does not submit a plan, or if the EPA does not approve a state's plan, then the EPA must establish a plan for that state.[5] Once a state receives the EPA's approval of its plan, the provisions in the plan become federally enforceable against the entity responsible for noncompliance, in the same manner as the provisions of an approved State Implementation Plan (SIP) under the Act.

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[1] CAA §111(b)(1)(A).
[2] See 40 CFR 60 subparts Cb – OOOO.
[3] CAA §111(b)(1)(B), 111(a)(1).
[4] CAA section 111(d)(2)(A).
[5] CAA section 111(d)(2)(A).

1.2.2 Market Failure

Many regulations are promulgated to correct market failures, which otherwise lead to a suboptimal allocation of resources within the free market. Air quality and pollution control regulations address "negative externalities" whereby the market does not internalize the full opportunity cost of production borne by society as public goods such as air quality are unpriced.

While recognizing that optimal social level of pollution may not be zero, GHG emissions impose costs on society, such as negative health and welfare impacts, that are not reflected in the market price of the goods produced through the polluting process. For this regulatory action the good produced is electricity. If a fossil fuel-fired electricity producer pollutes the atmosphere when it generates electricity, this cost will be borne not by the polluting firm but by society as a whole, thus the producer is imposing a negative externality, or a social cost of emissions. The equilibrium market price of electricity may fail to incorporate the full opportunity cost to society of generating electricity. Consequently, absent a regulation on emissions, the EGUs will not internalize the social cost of emissions and social costs will be higher as a result. This regulation will work towards addressing this market failure by causing affected EGUs to begin to internalize the negative externality associated with CO_2 emissions.

1.3 Background

1.3.1 Emission Guidelines

This analysis is intended to be an illustrative representation and analysis of the final ACE rule.[6] The final rule presents a framework for states to develop state plans that will establish standards of performance for existing affected sources of GHG emissions. The final rule does not itself specify any standard of performance, but rather establishes the "best system of emission reduction"[7] (BSER), i.e. technology for HRI. The HRI that were determined to be the BSER in this case is a list of six technologies that collectively have been deemed candidate technologies. States are responsible for applying the BSER to affected EGUs to determine standards of performance that consider each of the candidate technologies (as they are collectively the BSER). States may also take into account the remaining useful life and other source-specific

[6] For more details on legal authority and justification of this action, see rule preamble.
[7] The best system of emission reduction (BSER) informs the definition of "standard of performance" in CAA 111(a); see preamble for further discussion.

factors in the determination of the standards of performance. It is within the states' discretion for how to account for these unit specific considerations.

1.3.2 Regulated Pollutant

The purpose of this CAA section 111(d) rule is to address CO_2 emissions from fossil fuel-fired power plants in the U.S. because they are the largest domestic stationary source of emissions of carbon dioxide (CO_2). CO_2 is the most prevalent of the greenhouse gases (GHG), which are air pollutants that the EPA has determined endangers public health and welfare through their contribution to climate change.

1.3.3 Definition of Affected Sources for the Affordable Clean Energy Rule

As described in the preamble for this action, the EPA is finalizing that a "designated facility" subject to this regulation is any coal-fired electric utility steam generating unit that is not an integrated gasification combined cycle (IGCC) unit (i.e., utility boilers, but not IGCC units) that was in operation or had commenced construction as of August 31, 2018, and that meets the following criteria. To be a designated facility, a coal-fired electric utility steam generating unit must serve a generator capable of selling greater than 25 MW to a utility power distribution system and have a base load rating greater than 260 GJ/h (250 MMBtu/h) heat input of coal fuel (either alone or in combination with any other fuel).

1.4 Overview of Regulatory Impact Analysis

In accordance with Executive Order 12866, Executive Order 13563, OMB Circular A-4, and the EPA's *Guidelines for Preparing Economic Analyses*, 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.[8]

[8] The analysis in this final RIA constitutes the economic assessment required by CAA section 317. In EPA's judgment, the assessment is as extensive as practicable taking into account EPA's time, resources, and other duties and authorities.

In this RIA, the Agency provides both an analysis of the repeal of the CPP and a full benefit cost analysis of an illustrative policy scenario representing the final ACE rule, which models HRI at coal-fired EGUs.

For the analysis of the repeal of CPP (described in Chapter 2), the EPA examines a number of lines of evidence including: 1) several updated IPM modeling scenarios that consider different assumptions regarding implementation of the CPP (including that states are more likely to participate in interstate trading than previously analyzed, and that the Supreme Court stay leads to a delayed implementation of CPP), 2) consideration of the changes the EPA (and others, including EIA) have seen in CO_2 emissions across similar modeled scenarios and projections over time, 3) changing circumstances in the power sector (including fuel prices, technology changes and the age of different portions of the generating fleet), and 4) commitments many power companies have made to significantly reduce CO_2 emissions. Based on this examination, the EPA concludes that even if the CPP were implemented it would not achieve emission reductions beyond those that would be achieved without the CPP in place.

For the ACE analysis, the illustrative policy scenario represents potential outcomes of state determinations of standards of performance, and compliance with those standards by affected coal-fired EGUs. Because ACE is being analyzed as a separate action that occurs only after repeal of the CPP, the EPA is performing its analysis of ACE against a baseline without CPP (however as noted above, the EPA does not believe that there would be any significant differences between a scenario with or without CPP).

The illustrative policy scenario represents potential outcomes of state determinations of standards of performance, and compliance with those standards by affected coal-fired EGUs. This RIA has an updated representation of the expected future economic conditions affecting the electricity sector in the baseline from the proposed ACE rule. This RIA also reports the impact of climate benefits from changes in CO_2 and the impact on ancillary health benefits attributable to changes in SO_2 and NO_X emissions.

Additionally, this RIA includes information about potential impacts of the final rule on electricity markets, employment, and markets outside the electricity sector. The RIA also presents discussion of the uncertainties and limitations of the analysis.

1.4.1 Baseline

The analysis relies on the EPA's Power Sector Modeling Platform v6 using the Integrated Planning Model (IPM).[9] This accounts for changes in the power sector in recent years and projects our best understanding of important technological and economic trends into the future. The U.S. electric power sector has become less carbon intensive over the past several years, and this trend is projected to continue in the future, as documented in Chapters 2 and 3 of this RIA. These changes and trends are reflected in the modeling used for this analysis. As described earlier, the EPA is performing its analysis of ACE against a baseline without the CPP because ACE is being analyzed as a separate action that occurs only after repeal of the CPP.

Because air quality modeling was used to determine health benefits from changes in particulate matter and ozone concentrations that may occur because of this rule, the baseline includes emissions from all sources. Consequently, in addition to rules and economic conditions included in the IPM Reference Case, the baseline for this analysis included emissions from, and rules for, non-EGU point sources, on-road vehicles, non-road mobile equipment and marine vessels.[10] Additional information on what is included in the air quality modeling inventory is detailed in Chapter 4 and Chapter 8.

This analysis reflects the best data available to the EPA at the time it was conducted. As with any modeling of future projections, many of the inputs are uncertain. In this context, notable uncertainties include the cost of fuels, the cost to operate existing power plants, the cost to construct and operate new power plants, infrastructure, demand, and policies affecting the electric power sector. The modeling conducted for this RIA is based on estimates of these variables, which were derived from the data currently available to the EPA. However, future realizations of these characteristics may deviate from expectations. The results of counterfactual simulations presented in this RIA are not a prediction of what will happen, but rather projections of a plausible scenario describing how this final regulatory action may affect electricity sector

[9] For documentation, see https://www.epa.gov/airmarkets/clean-air-markets-power-sector-modeling

[10] Using the air quality modeling techniques in this RIA, the impacts of these non-EGU rules are determined as of 2023, so any implementation or effects expected to occur after 2023 are not accounted for in this RIA. However, the effect of non-EGU emissions on changes in pollution concentrations due to changes in emissions in the electricity sector between the baseline and the illustrative policy scenario is likely small.

outcomes in the absence of unexpected shocks. The results of this RIA should be viewed in that context.

1.4.2 BSER and Illustrative Policy Scenario

The illustrative policy scenario models HRIs applied at affected coal-fired EGUs in the contiguous U.S. beginning in 2025. The EPA has identified the BSER to be HRI. In the final Emission Guidelines, the EPA provides states with a list of candidate HRI technologies that must be evaluated when establishing standards of performance. The cost, suitability, and potential improvement for any of these HRI technologies is dependent on a range of unit-specific factors such as the size, age, fuel use, and the operating and maintenance history of the unit. As such, the HRI potential can vary significantly from unit to unit. The EPA does not have sufficient information to assess HRI potential on a unit-by-unit basis. CAA 111(d) also provides states with the responsibility to establish standards of performance and provides considerable flexibility in the establishment of those emission standards. States may take many factors into consideration – including among other factors, the remaining useful life of the affected source – when applying the standards of performance.[11] Therefore, any analysis of the final rule is illustrative. However, the EPA believes that such illustrative analyses can provide important insights at the national level and can inform the public on a range of potential outcomes. Additional information describing the analytical basis for the illustrative policy scenario is provide in Section 1.6.

1.4.3 Years of Analysis

We evaluate the potential regulatory impacts of the illustrative policy scenario using the present value (PV) of costs, benefits, and net benefits, calculated for the years 2023-2037 from the perspective of 2016, using both a three percent and seven percent end-of-period discount rate. In addition, the Agency presents the assessment of costs, benefits, and net benefits for specific snapshot years, consistent with historic practice. In this RIA, the regulatory impacts are evaluated for the specific years of 2025, 2030, and 2035.

The Agency believes that these specific years are each representative of several surrounding years, which enables the analysis of costs and benefits over the timeframe of 2025-

[11] See Section III of the preamble for a discussion of factors that states may consider in establishing a standard of performance in response to this emission guideline.

2037. The year 2025 is an approximation for when the standards of performance under the final rule might be implemented, and the Agency estimates that monitoring, reporting, and recordkeeping (MR&R) costs may begin in 2023. Therefore, MR&R costs analysis is presented beginning in the year 2023, and full benefit cost analysis is presented beginning in the year 2025. The analytical timeframe concludes in 2037, as this is the last year that may be represented with the analysis conducted for the specific year of 2035.

1.5 BSER Technologies

The list of candidate technologies that constitute the BSER are summarized below and are described in greater detail in Section III of the preamble.

1.5.1 Neural Network/Intelligent Sootblower

1.5.1.1 Neural Networks

Computer models, known as neural networks, can be used to simulate the performance of the power plant at various operating loads. Typically, the neural network system ties into the plant's distributed control system for data input (process monitoring) and process control. The system uses plant specific modeling and control modules to optimize the unit's operation and minimize the emissions. This model predictive control can be particularly effective at improving the plants performance and minimizing emissions during periods of rapid load changes. The neural network can be used to optimize combustion conditions, steam temperatures, and air pollution control equipment.

1.5.1.2 Intelligent Sootblowers

During operations at a coal-fired power plant, particulate matter (PM) (ash or soot) builds up on heat transfer surfaces. This build-up degrades the performance of the heat transfer equipment and negatively affects the efficiency of the plant. Power plant operators use steam injection "sootblowers" to clean the heat transfer surfaces by removing the ash build-up. This is often done on a routine basis or as needed based on monitored operating characteristics. Intelligent sootblowers (ISB) are automated systems that use process measurements to monitor the heat transfer performance and strategically allocate steam to specific areas to remove ash buildup.

The cost to implement an ISB system is relatively inexpensive if the necessary hardware is already installed. The ISB software/control system is often incorporated into the neural network software package mentioned above. As such, the HRIs obtained via installation of neural network and ISB systems are not necessarily cumulative.

1.5.2 Boiler Feed Pumps

A boiler feed pump (or boiler feedwater pump) is a device used to pump feedwater into a boiler. The water may be either freshly supplied or returning condensate produced from condensing steam produced by the boiler. The boiler feed pumps consume a large fraction of the auxiliary power used internally within a power plant. Boiler feed pumps can require power in excess of 10 MW on a 500-MW power plant. Therefore, the maintenance on these pumps should be rigorous to ensure both reliability and high-efficiency operation. Boiler feed pumps wear over time and subsequently operate below the original design efficiency. The most pragmatic remedy is to rebuild a boiler feed pump in an overhaul or upgrade.

1.5.3 Air Heater and Duct Leakage Control

The air pre-heater is a device that recovers heat from the flue gas for use in pre-heating the incoming combustion air, and potentially for other uses such as coal drying. Properly operating air pre-heaters play a significant role in the overall efficiency of a coal-fired EGU. The air pre-heater may be regenerative (rotary) or recuperative (tubular or plate). A major difficulty associated with the use of regenerative air pre-heaters is air in-leakage from the combustion air side to the flue gas side. Air in-leakage affects boiler efficiency due to lost heat recovery and affects the axillary load since any in-leakage requires additional fan capacity. The amount of air leaking past the seals tends to increase as the unit ages. Improvements to seals on regenerative air pre-heaters have enabled the reduction of air in-leakage.

1.5.4 Variable Frequency Drives (VFDs)

1.5.4.1 VFD on Induced Draft (ID) Fans

The increased pressure required to maintain proper flue gas flow through downstream air pollutant control equipment may require additional fan power, which can be achieved by an ID fan upgrade/replacement or an added booster fan. Generally, older power plant facilities were designed and built with centrifugal fans.

The most precise and energy-efficient method of flue gas flow control is use of VFD. The VFD controls fan speed electrically by using a static controllable rectifier (thyristor) to control frequency and voltage and, thereby, the fan speed. The VFD enables very precise and accurate speed control with an almost instantaneous response to control signals. The VFD controller enables highly efficient fan performance at almost all percentages of flow turndown. Due to current electricity market conditions, many units no longer operate at base-load capacity and, therefore, VFDs, also known as variable-speed drives on fans can greatly enhance plant performance at off-peak loads.

1.5.4.2 VFD on Boiler Feed Pumps

VFDs can also be used on boiler feed water pumps as mentioned previously. Generally, if a unit with an older steam turbine is rated below 350 MW, the use of motor-driven boiler feedwater pumps as the main drivers may be considered practical from an efficiency standpoint. If a unit cycles frequently then operation of the pumps with VFDs will offer the best results on heat rate reductions, followed by fluid couplings. The use of VFDs for boiler feed pumps is becoming more common in the industry for larger units. And with the advancements in low pressure steam turbines, a motor-driven feed pump can improve the thermal performance of a system up to the 600-MW range, as compared to the performance associated with the use of turbine drive pumps. Smaller and older units will generally not upgrade to a VFD boiler feed pump drive due to high capital costs.

1.5.5 Blade Path Upgrade (Steam Turbine)

Upgrades or overhauls of steam turbines offer the greatest opportunity for HRI on many units. Significant increases in performance can be gained from turbine upgrades when plants experience problems such as steam leakages or blade erosion. The typical turbine upgrade depends on the history of the turbine itself and its overall performance. The upgrade can entail myriad improvements, all of which affect the performance and associated costs. The availability of advanced design tools, such as computational fluid dynamics (CFD), coupled with improved materials of construction and machining and fabrication capabilities have significantly enhanced the efficiency of modern turbines. These improvements in new turbines can also be utilized to improve the efficiency of older steam turbines whose efficiency has degraded over time.

1.5.6 Redesign/Replace Economizer

In steam power plants, economizers are heat exchange devices used to capture waste heat from boiler flue gas which is then used to heat the boiler feedwater. This use of waste heat reduces the need to use extracted energy from the system and, therefore, improves the overall efficiency or heat rate of the unit. As with most other heat transfer devices, the performance of the economizer will degrade with time and use, and power plant representatives contend that economizer replacements are often delayed or avoided due to concerns about triggering NSR. In some cases, economizer replacement projects have been undertaken concurrently with retrofit installation of selective catalytic reduction (SCR) systems because the entrance temperature for the SCR unit must be controlled to a specific range.

1.5.7 Additional Documentation

Government agencies and laboratories, industry research organizations, engineering firms, equipment suppliers, and environmental organizations have conducted studies examining the potential for improving heat rate in the U.S. EGU fleet or a subset of the fleet. Section III of the preamble provides a list of some reports, case studies, and analyses of these HRI technologies that are BSER, as well as those that are not BSER, in the U.S.

1.6 Development of Illustrative Policy Scenario

1.6.1 Introduction

The illustrative policy scenario, which represents the ACE rule, is based on a bottom-up analyses of fleet-wide HRI potential by identifying HRI technologies that may be available to certain categories of coal-fired EGUs.[12] In the analyses, the EPA considered how the available HRI measures that are included in the BSER list of candidate technologies may apply to these categories. This approach defined a set of 12 bins for coal steam units that were then linked to

[12] This methodology is similar to the bottom-up approach used by the Energy Information Administration (EIA, 2015) to identify the possible HRI available at different categories of coal-fired units. However, the suite of HRI technologies, and their associated costs and performance, represented in the EIA study differ from those used here.

potential HRIs based on technologies presented in the Sargent & Lundy (S&L) report[13] and discussed above as BSER for the final ACE rule.[14]

1.6.2 Grouping EGUs by Performance

The fleet of coal-fired EGU with greater than 25 MW of capacity – defined in the units in the NEEDS_v6 database[15] (September 2018 revision) that are not retiring by 2021 – was rank-ordered by heat rate from most efficient (*i.e.*, lowest heat rate) to least efficient (*i.e.*, highest heat rate).[16] The NEEDS database contains the generation unit records used to construct the "model" plants that represent existing and planned/committed units in the EPA modeling applications of IPM. The fleet was then divided into four groups using a methodology described below and referred to as Group 1 through Group 4. Group 1 represents the most efficient units in the fleet. Those units are assumed to have little to no potential for further HRI applying the BSER technologies. Group 4 represents the least efficient units in the fleet and those units are assumed to have the most opportunity for HRI applying these technologies. Groups 2 and 3 represent the remaining units and are assumed to have intermediate opportunities for HRI.

Specifically, we defined the groups using a capacity weighted heat rate distribution for the fleet. Group 1 was defined as units with a heat rate one capacity weighted standard deviation below the capacity weighted mean heat rate and Group 4 was defined as units with a heat rate one capacity weighted standard deviation above the capacity weighted mean heat rate. Groups 2 and 3 were defined as units within one capacity weighted standard deviation below and above the capacity weighted mean heat rate, respectively. The capacity weighted mean heat rate, $\bar{h}_w$, across the N coal steam units in the fleet is defined as

[13] "Coal-Fired Power Plant Heat Rate Reductions" Sargent & Lundy Report SL-009597 (2009); available in the rulemaking docket at EPA-HQ-OAR-2017-0355-21171.
[14] For more information, see 83 FR 44746; Table 1 and Table 2.
[15] National Electric Energy Data System, NEEDS_v6, available in the rulemaking docket at EPA-HQ-OAR-2017-0355-21141; available on-line at https://www.epa.gov/airmarkets/national-electric-energy-data-system-needs-v6.
[16] The heat rates for the model plants in EPA Platform v6 are based on values from Annual Energy Outlook 2017 informed by fuel use and net generation data reported on Form EIA-923. For further explanation see IPM documentation: https://www.epa.gov/airmarkets/clean-air-markets-power-sector-modeling

$$\bar{h}_w = \frac{\sum_{i=1}^{N} c_i h_i}{\sum_{i=1}^{N} c_i} ,$$

h_i is the heat rate for unit i and c_i is the capacity (in megawatts, MW). The weighted standard deviation, s_w, is defined as

$$s_w = \sqrt{\frac{\sum_{i=1}^{N} c_i \left(h_i - \bar{h}_w\right)^2}{\frac{(N-1)\sum_{i=1}^{N} c_i}{N}}} .$$

Based on these definitions and the approach for defining the groups, the heat rate cutoffs for the four groups are presented below in Table 1-1 and the distribution of capacity across heat rates and groups is presented in Figure 1-1.

Table 1-1 Heat Rate Ranges Defining Groups

	Heat Rate Range [Btu/kWh]
Group 1 (Most Efficient)	≤ 9,773
Group 2	9,774 – 10,396
Group 3	10,397 – 11,019
Group 4 (Least Efficient)	≥ 11,020

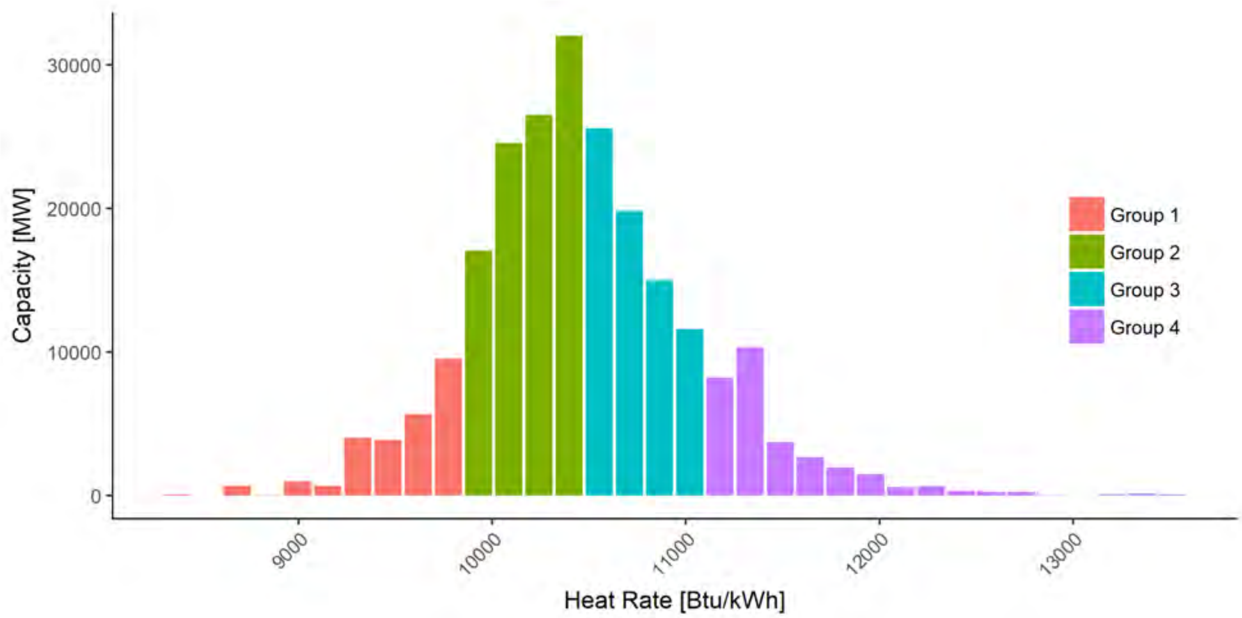

Figure 1-1 Distribution of Heat Rates and Unit Groups

The units were further divided in each group according to amount of generating capacity consistent with ranges presented in the proposal for the ACE rule.[17] The breakdown of units – the number of EGUs and the total capacity (MW) – in each of the 12 bins is shown in Table 1-2. The breakdown of units – the percent of total units and the percent of total capacity – is provided in Table 1-3.

Table 1-2 Number of Coal-Fired EGUs >=25MW and Total Capacity (MW) in Each Heat Rate Group Bin

	< 200 MW	200 - 500 MW	> 500 MW
Group 1	4 EGUs (130 MW)	6 EGUs (2,226 MW)	31 EGUs (23,225 MW)
Group 2	12 EGUs (1,827 MW)	45 EGUs (16,161 MW)	113 EGUs (82,203 MW)
Group 3	61 EGUs (8,232 MW)	86 EGUs (29,430 MW)	48 EGUs (29,259 MW)
Group 4	101 EGUs (8,877 MW)	48 EGUs (15,372 MW)	11 EGUs (7,549 MW)

Note: Source data is from National Electric Energy Data System, NEEDS_v6

[17] For more information, see 83 FR 44746; Table 1 and Table 2.

Table 1-3 Percent of Total Coal-Fired EGUs >-25MW and Percent of Coal-Fired Total Capacity (MW) in Each Heat Rate Group Bin

	< 200 MW	200 - 500 MW	> 500 MW
Group 1	1% / < 1 %	1 % / 1 %	6 % / 10 %
Group 2	2 % / 1 %	8 % / 7 %	20 % / 37 %
Group 3	11 % / 4 %	15 % / 13 %	9 % / 13 %
Group 4	18 % / 4 %	9 % / 7 %	2 % / 3 %

1.6.3 Heat Rate and Cost for each Bin

While many potential HRI measures have been identified, some of those identified technologies have limited applicability and many provide only negligible HRI.[18] The EPA stated in the ACE proposal that evaluation of the entire list of potential HRI options – including those with limited applicability and with negligible benefits – may be overly burdensome to the states. Therefore, the EPA identified and proposed a list of the "most impactful" HRI technologies, equipment upgrades and best operating and maintenance practices that form the list of "candidate technologies" constituting the BSER. Those technologies were ones that the EPA determined to provide meaningful HRI opportunity, to be broadly applicable, and to be implementable at reasonable cost and are being finalized as BSER in this rule.

Based on the S&L report, the potential ranges of HRI for these technologies are presented in Table 1-4 and the ranges of costs (updated to $2016) for those improvements are presented in Table 1-5. These are the six HRI "candidate technologies" identified as BSER in the proposed ACE rule and are the six technologies that are identified as BSER in the final ACE rule. The first four HRI options listed in each table are assumed to be broadly available. The last two HRI options – "Blade Path Upgrade (Steam Turbine)" and "Redesign/Replace Economizer" – are technologies that, based on program experience and industry comments, are assumed to be more likely to trigger additional secondary costs including costs associated with NSR permitting. With these and other additional costs, the remaining useful life of the facilities may be reduced such that we assume that these two technologies are less likely to be implemented. This is consistent with assumptions provided in cost and impact analyses supporting the ACE rule proposal.

[18] For more information, see Table 3 in 82 FR 61515.

Table 1-4 S&L Heat Rate Improvements (Percentage) by EGU Size

	< 200 MW		200 - 500 MW		> 500 MW	
	Min	Max	Min	Max	Min	Max
Neural Network/Intelligent Sootblowers	0.5	1.4	0.3	1.0	0.3	0.9
Boiler Feed Pumps	0.2	0.5	0.2	0.5	0.2	0.5
Air Heater & Duct Leakage Control	0.1	0.4	0.1	0.4	0.1	0.4
Variable Frequency Drives	0.2	0.9	0.2	1.0	0.2	1.0
Subtotal	1.0	3.2	0.8	2.9	0.8	2.8
Blade Path Upgrade (Steam Turbine)	0.9	2.7	1.0	2.9	1.0	2.9
Redesign/Replace Economizer	0.5	0.9	0.5	1.0	0.5	1.0
Total	2.4	6.8	2.3	6.8	2.3	6.7

Table 1-5 S&L Heat Rate Improvement Costs [2016$/kW] by EGU Size

	< 200 MW		200 - 500 MW		> 500 MW	
	Min	Max	Min	Max	Min	Max
Neural Network/Intelligent Sootblowers	4.7	4.7	2.5	2.5	1.4	1.4
Boiler Feed Pumps	1.4	2.0	1.1	1.3	0.9	1.0
Air Heater & Duct Leakage Control	3.6	4.7	2.51	2.7	2.1	2.4
Variable Frequency Drives	9.1	11.9	7.2	9.4	6.6	7.9
Subtotal	18.8	23.3	13.3	15.9	11.0	12.7
Blade Path Upgrade (Steam Turbine)	11.2	66.9	8.9	44.6	6.2	31.0
Redesign/Replace Economizer	13.1	18.7	10.5	12.7	10.0	11.2
Total	43.1	108.9	32.7	73.2	27.2	54.9

The EGUs in Group 1 are the most efficient units in the fleet and for the purposes of modelling the illustrative policy scenario were assumed to have no opportunities to implement any of the candidate technologies to improve their performance (*i.e.*, these units are assumed to be very well maintained and to have already implemented available HRI technologies). The EGUs in Groups 2 and 3 are the mid-range units and were assumed to implement the first four HRIs in Table 1-4. The units in Group 2 were assumed to achieve the minimum HRI in the range while the units in Group 3 were assumed to make the same improvements but to achieve the midpoint of the range in available HRI (in percent). The EGUs in Group 4 are the least efficient units. Those EGUs were assumed to make the same four HRIs as the units in Groups 2 and 3 but were assumed to achieve the maximum improvement within the range. None of the Groups were assumed to adopt the last two HRIs as it was assumed (based on industry comments) that they are less likely to be installed to the extent they could trigger NSR permitting affecting remaining useful life,[19] as noted above.

Note that these assumptions regarding implementation and cost of HRI at particular EGUs are illustrative and are only intended as a means of providing a reasonable estimate of the possible costs, benefits and impacts for the final ACE rule. The assumptions are not intended to imply applicability of any specific improvement measure at any specific type of EGU. The EPA has limited information on the specific HRI options that may or may not be implemented at any specific EGU. In developing their implementing plans, the states will evaluate the applicability of each of the HRI options provided in Table 1-4 to each EGU within their borders and determine a unit-specific emission standard based on implementation of those technologies which represent the BSER.

Once the EGUs were ranked and grouped according to the heat rate, each of the four resulting groups was further divided into three bins based on size in megawatts (MW) – resulting in 12 total bins. Given these assumptions the HRI potential by group and size are presented in Table 1-6. These assumed HRI potentials serve as inputs for the IPM modelling.

Table 1-6 Group Specific Heat Rate Improvements (Percentage)

	< 200 MW	200 - 500 MW	> 500 MW
Group 1	0.0	0.0	0.0
Group 2	1.0	0.8	0.8
Group 3	2.1	1.9	1.8
Group 4	3.2	2.9	2.8

Independent of the group it was assumed that the HRI costs are defined by the maximum value within the given size range. Several commenters noted that the improved performance obtained from investment in HRI measures will degrade over time and that the EGUs will have to reinvest to maintain the level of performance. The lifetime of these HRIs was assumed to be approximately 8 years (*i.e.*, it was assumed that the units would need to reinvest in additional HRI at least once during the 2025-2037 timeframe in which costs are considered in this RIA).

[19]The EPA is not finalizing proposed changes to the New Source Review program in the final ACE rulemaking. If the EPA decides to finalize changes to the NSR program, it will be done in a subsequent rulemaking action and these modelling assumptions will be revisited at that time.

The EPA conservatively assumed that all HRI technologies are implemented at the higher end of the ranges presented in Table 1-5. The EPA also assumed that the costs are doubled as a way of representing reinvestment over time to account for performance degradation. The total costs associated with the HRIs (initial investment and a one-time reinvestment) are given in Table 1-7. These assumed HRI costs serve as inputs for the IPM modelling. That is, each unit within a group is assumed to incur the same percentage HRI and associated cost per kW as reported in Tables 1-6 and 1-7 as all other units in that group.

Table 1-7 Group Specific Heat Rate Improvement Costs [$2016/kW]

	< 200 MW	200 - 500 MW	> 500 MW
Group 1	0.0	0.0	0.0
Group 2	47.0	32.0	25.0
Group 3	47.0	32.0	25.0
Group 4	47.0	32.0	25.0

In the illustrative policy scenario the average capacity-weighted HRI is 1.5 percent with an average cost of $29/kW (for those units assumed to implement HRIs, *i.e.*, Groups 2 – 4). The most comparable illustrative policy scenario presented in the ACE proposal assumed a fleetwide HRI of 2 percent at a cost of $50/kW.[20] That illustrative policy scenario also assumed lower HRI opportunity without changes to the NSR program.

1.6.4 How HRI are Represented in the Illustrative Policy Scenario

As discussed above, the final rule requires states to develop standards of performance based on the BSER, which the EPA has determined to be HRI at existing EGUs. Conceptually, the illustrative policy scenario presumes required standards of performance that are established by the states and assume an approach for how each affected source complies with its standard of performance (and associated cost of that approach per kW of installed capacity). However, the standards of performance are not represented in the model directly and, as discussed above, are uncertain because the applicability of these HRI technologies across the fleet and the standards

[20] The 2 percent HRI improvement and $50/kW was applied uniformly to each coal-fired EGU >=25 MW capacity.

of performance the states will require are uncertain.[21] In practice, affected sources may have certain flexibilities in how they comply with the standards of performance that differ from the technologies used to determine the sources' standards of performance, but this possibility is not captured in the modeling for this RIA. For ease of modeling, in the illustrative policy scenario, sources may adopt the assumed HRI level or may retire in the model, based on prevailing economics. However, it is possible that States may use opportunities afforded to them in the final rule when setting standards of performance that will vary based on source-specific factors, and the illustrative policy scenario does not capture this possibility. A discussion of establishing standards of performance by states can be found in section III.F.1. of the preamble.

The illustrative policy scenario reflects technology improvements applied to groups of coal-fired units based upon unit size and efficiency. Again, it is important to note that current data limitations hinder our ability to apply more customized HRI and cost functions to specific units. Due to these limitations, as described above the EPA used the best available information, research, and analysis to arrive at the assumptions used in the illustrative policy scenario.

1.7 Organization of the Regulatory Impact Analysis

This report presents the EPA's analysis of the potential costs, benefits, and other economic effects of the final action to fulfill the requirements of an RIA. This RIA includes the following chapters:

- Chapter 2, Impacts of the Repeal of the CPP
- Chapter 3, Costs, Emissions, Economic, and Energy Impacts
- Chapter 4, Estimated Forgone Climate Benefits and Forgone Human Health Co-Benefits
- Chapter 5, Economic and Employment Impacts
- Chapter 6, Comparison of Benefits and Costs
- Chapter 7, Appendix – Uncertainty Associated with Estimating the Social Cost of Carbon
- Chapter 8, Appendix – Air Quality Modeling

[21] Note that, in the modeling, the total cost of the HRI is reflected as a capital cost. However, for some HRI technologies, a small share of the total cost may be variable, and thus might have a small effect on dispatch decisions.

1.8 References

40 CFR Chapter I [EPA–HQ–OAR–2009–0171; FRL–9091–8] RIN 2060–ZA14, “Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202(a) of the Clean Air Act,” Federal Register / Vol. 74, No. 239 / Tuesday, December 15, 2009 / Rules and Regulations.

U.S. Energy Information Administration (EIA), “Analysis of Heat Rate Improvement Potential at Coal-Fired Power Plants”, May 2015.

U.S. Environmental Protection Agency (EPA). 2018. *Regulatory Impact Analysis for the Proposed Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units; Revisions to Emission Guideline Implementing Regulations; Revisions to New Source Review Program*. EPA-452/R-18-006. Office of Air Quality Planning and Standards, Health and Environmental Impacts Division, Research Triangle Park, NC.

CHAPTER 2: IMPACTS OF THE REPEAL OF THE CPP

2.1 Introduction

As the EPA explained in the preamble, the repeal of the Clean Power Plan (CPP) and the promulgation of a new set of 111(d) guidelines are two separate actions. Consistent with that position, the EPA is providing a separate analysis of both actions in this RIA. The bulk of the RIA focuses on an analysis of the ACE rule against a baseline that does not include the CPP. This is because the ACE action only occurs after the repeal of the CPP.

This chapter presents EPA's analysis of the CPP repeal. It explains how after reviewing the comments, the EPA ultimately concluded that while deregulatory in nature and important to address the overreach of the CPP, fully considering a number of factors, the most likely result of implementation of the CPP would be no change in emissions and therefore no cost savings or changes in health disbenefits relative to a world without the CPP. This conclusion (i.e., that repeal of the CPP has no effect against a baseline that includes the CPP) – is appropriate for several reasons, consistent with OMB's guidance that the baseline for analysis "should be the best assessment of the way the world would look absent the proposed action."[1] It is the EPA's consideration of the weight of the evidence, taking into account the totality of the available information, as presented below, that leads to the finding and conclusion that there is likely to be no difference between a world where the CPP is implemented and one where it is not. As further explained in this section, the EPA comes to this conclusion not through the use of a single analytical scenario or modeling alone, but rather through the weight of evidence that includes: several IPM scenarios that explore a range of changes to assumptions about implementation of the CPP, consideration of the ongoing evolution and change of the electric sector, and recent commitments by many utilities that include long-term CO_2 reductions across the EGU fleet.

Setting aside the Agency's position that the CPP is an unlawful exercise of authority under section 111(d), the rule would have little or no impact regardless of the outcome of the petitions for judicial review of the CPP. The EPA has conducted several IPM modeling scenarios of CPP that demonstrate there is likely to be little or no difference between a future scenario with

[1] OMB circular A-4, at 15.

the CPP and one without it. To establish this, the EPA conducted updated modeling for three CPP implementation scenarios, and also considered the most up-to-date information about the electric sector that is not yet incorporated into the EPA's modeling. The EPA first modeled the CPP under one of its previous implementation assumptions—i.e., with mass-based compliance beginning in 2022 and no interstate trading, primarily for consistency purposes. This modeling shows the CPP is "non-binding" in more than half of the states even under these conservative assumptions. That is, the CPP does not require additional CO_2 emission reductions beyond the baseline (for many states) and thus does not "bind" affected sources to an emission reduction requirement in the sense of driving further emission-reducing actions.

However, these implementation assumptions for the CPP no longer reflect reasonable expectations regarding how the CPP hypothetically would be implemented. As explained below, the EPA does not believe implementation of CPP state-level goals would be implemented without interstate trading. Further, due to the judicial stay of the CPP in February of 2016, it is not reasonable to assume CPP implementation would begin in 2022. For these reasons, the EPA has conducted new analysis of the CPP using revised assumptions, with implementation beginning in 2025 and states engaging in interstate trading.[2]

EPA examined two additional CPP scenarios: one with national trading and one with regional trading (and both with delayed implementation of CPP). While the national trading scenario is theoretically possible[3], based on discussions that states were having prior to the stay of CPP, EPA believes that some level of regional trading would have been the most likely outcome of CPP implementation. As is further explained below, there are a number of reasons to believe that these modeling scenarios are overstating future emissions and that given the small differences seen between these modeling scenarios and the no CPP case, the CPP would ultimately be extremely unlikely to result in emission reductions beyond a business as usual case.

The conclusions that can be drawn from this modeling are supported by the most up-to-date information regarding this sector, including very recent changes not yet incorporated into

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[2] The preamble of the CPP final rule discusses multi-state plans and multi-state coordination that would facilitate interstate trading under the CPP (80 Fed Reg 64838-40).

[3] EPA views the development of a national GHG allowance trading market as less likely, due to a number of considerations, such as the regionalized nature of organized electricity markets as well as efforts that were going on at the state level when the rule was stayed.

the EPA's modeling. There have been significant changes in the electric sector since the EPA finalized the CPP in August of 2015 that lead the EPA to different conclusions about the potential impacts of the CPP. These include fundamental shifts in fuel supply, continued advances and cost declines for key power generating technologies, market operation and policy evolution, and end-use demand influences. These changes can be observed using recent historical data trends, current utility operations and planning, and utility announcements and power sector projections.

These trends can also be seen in the evolution of the EPA's modeling of the CPP, even under its prior assumptions. The EPA has modeled the CPP assuming a mass-based implementation with no interstate trading four times, beginning with the final CPP in August of 2015. Key results of these modeling exercises are summarized in the table below. In each of the cases summarized below, the EPA made a conservative assumption by assuming no interstate trading. However, each iterative modeling effort reflected updated information on key inputs such as the cost of new generation technologies, firmly committed coal retirements, state and federal policies, and projected demand (amongst others). While these scenarios represent a less likely current scenario (both because they assume no interstate trading and because they make no account for the current stay of the Clean Power Plan), they do provide useful information to document progress that has been made at the state level since the CPP was finalized. In particular, EPA believes allowance prices provide a useful measuring stick to assess both the degree of stringency and magnitude of impact of the CPP requirements.

Table 2-1 Select IPM Results for CPP

IPM Modeling Projections of CPP (Using a Mass-based approach where State-by-State Goals must be met)				
Scenario that includes CPP, for the year 2030	**Final CPP RIA (v5.15)**	**Ozone NAAQS Transport NODA (v5.16)**	**Proposed ACE (v6.17)**	**Final ACE (IPM 2018)**
Average Marginal Cost, all States (\$/ton CO_2)	\$11	\$4	\$2	\$2
Highest Marginal Cost (\$/ton CO_2)	\$26	\$17	\$11	\$13
# of States with \$0/ton	7	18	30	27
Total Power Sector CO_2 (million short tons)	1,814	1,839	1,737	1,681
% below 2005	32.4%	31.4%	35.3%	37.3%

As can be seen from the results in Table 2-1, if the CPP were to be implemented even with the conservative assumption of no interstate cooperation and ignoring any delay in implementation due to the Supreme Court stay, the impacts of the CPP would be significantly less than the EPA projected in its original CPP analysis. In August of 2015, the EPA projected that only 7 of the 47 states with CPP obligations were already on track to meet those obligations (15%). Now the EPA is projecting that at least 27 states (57%) are on track to meet or exceed their targets. These reductions are attributable to trends that result in emission reductions regardless of the CPP. Even for states that are not currently projected as on track to meet their goals, those targets have become significantly easier to attain. The marginal cost for achieving a state goal in the state with the highest marginal cost has fallen from \$26/ton to \$13/ton.[4] More detail on the state by state results can be found in Table 2-4, which shows that in August of 2015, EPA projected that 7 states would have allowance prices of \$20 or more. In the modeling using

[4] Marginal costs are reported in 2016\$ per short ton of CO_2 throughout this chapter.

the 2018 IPM, EPA projects that none do (notably, for two of those states Arizona and Utah, EPA is now projecting an allowance price of zero).The table also shows that 29 states had an allowance price of $10 or more. In the IPM 2018 modeling, there are only two. One of those states, Colorado, is home to utilities that have made significant CO_2 reduction commitments that are not fully reflected in the IPM modeling. Further, as presented below, under reasonable revised assumptions of delayed implementation and interstate trading, the CPP is non-binding entirely (in the sense of not requiring any additional CO_2 emission reductions beyond the baseline).

Given these findings, as well as ongoing market trends and numerous recent utility CO_2 reduction announcements, the EPA believes repeal of the CPP under current and reasonably projected market conditions and regulatory implementation is not anticipated to have a meaningful effect on emissions of CO_2 or other pollutants or regulatory compliance costs. As a result, this analysis demonstrating no significant difference in a scenario with CPP implementation and one without satisfies any regulatory impact analysis that may be required by statute or executive order for repeal of the CPP.

Section 2.2 provides information pertaining to the changes that have occurred in the electric sector that have led to these projected changes. Section 2.3 explores the impact of alternative trading assumptions and Section 2.4 summarizes key changes that may not be fully incorporated into the EPA's current modeling. Section 2.5 examines several states projected to have emission-reduction shortfalls in the EPA's modeling (i.e., higher baseline emissions than their CPP goals) and provides additional real-world context for interpreting these modeling outputs. Section 2.6 summarizes why these considerations together lead the EPA to conclude that, even if the CPP were upheld, emissions projections would not be noticeably different from a case where the CPP is not implemented. As a result, the cost and benefit impacts of CPP repeal are de minimis. Finally, Section 2.7 presents additional summary information from IPM runs used to support this analysis.

2.2 Market Trends for the Electric Sector Relevant to Consideration of the Impact of the Repeal of the CPP

A critical element of ongoing assessment and evaluation of the power sector are the current trends underway, whereby the sector is experiencing a greater degree of change in generation mix than it has historically. While many of these trends are incorporated into the EPA's updated modeling analysis and result in lower emissions projections absent any CO_2 regulatory considerations for power plants at the federal level, there is significant evidence that these trends are occuring at a faster rate than most electric sector modeling has been projecting (see, for instance, the discussion of the evolution of the levelized cost of electricity by generation type below). The anticipation of a lower emissions future in the baseline is due to large-scale market trends that are multi-faceted in nature. These include fundamental shifts in fuel supply, continued advances and cost declines for key power generating technologies, market operation and policy evolution, and end-use demand influences. These changes can be observed using recent historical data trends, current utility operations and planning, and utility announcements and power sector projections for the future that go through 2030, and beyond.

Ultimately, these trends are anticipated to result in the continued decline of coal-fired generation and capacity and significant increases in natural gas-fired generation and capacity. At the same time, renewable energy has continued to be the fastest growing form of new utility-scale electric-generating capacity and is expected to account for a significant portion of all new capacity into the future. In addition, electricity demand is only slowly rising. This places additional economic pressures on older and less-efficient technologies (like many existing coal-fired plants), which struggle to compete with the newer capacity coming online that generally has lower operating costs. These findings have been summarized in a recent report from DOE:[5]

- "The biggest contributor to coal and nuclear plant retirements has been the advantaged economics of natural gas-fired generation."
- "Another factor contributing to the retirement of power plants is low growth in electricity demand."

[5] U.S. Department of Energy. (2017). Staff Report to the Secretary on Electricity Markets and Reliability. Retrieved from https://www.energy.gov/sites/prod/files/2017/08/f36/Staff%20Report%20on%20Electricity%20Markets%20and%20Reliability_0.pdf

- "Dispatch of variable renewable energy (VRE) has negatively impacted the economics of baseload plants."

The changes in the generation mix away from coal and toward lower- and zero-emitting generation are significantly more pronounced than the EPA and other analysts projected when the EPA finalized the CPP. These trends mean that the states would be able to meet their goals and, ultimately, the sources to meet their emission standards, with less planning burden, at significantly less cost, and with less impact on the sector than the EPA previously estimated when it finalized the CPP.

2.2.1 Recent Data Trends

2.2.1.1 Age of the Coal Fleet & Retirements

The current fleet of coal-fired power plants was mostly built prior to 1990,[6] with an average age of 39 years. Nearly all of the utility-scale power plants in the U.S. that were retired from 2008 through 2017 were fueled by fossil fuels, and coal-fired power plants accounted for the highest percentage.[7] The average age of coal-fired power plants that have retired since 2008 is 52 years. Older power plants tend to become uneconomic over time as they become more costly to maintain and operate, and as newer and more efficient alternative generating technologies are built. As a result, coal's share of total U.S. electricity generation has been declining for over a decade, while generation from natural gas and renewables has increased significantly. The reduction in coal demand from power plants has also resulted in declining coal consumption, with expected total U.S. coal consumption in 2018 of 691 million short tons (a 4% decline from 2017 and the lowest level since 1979).[8]

[6] EIA, Today in Energy (April 17, 2017), *available at* https://www.eia.gov/todayinenergy/detail.php?id=30812.
[7] EIA, Today in Energy (December 19, 2018), *available at* https://www.eia.gov/todayinenergy/detail.php?id=37814.
[8] EIA, Today in Energy (December 28, 2018), *available at* https://www.eia.gov/todayinenergy/detail.php?id=37817.

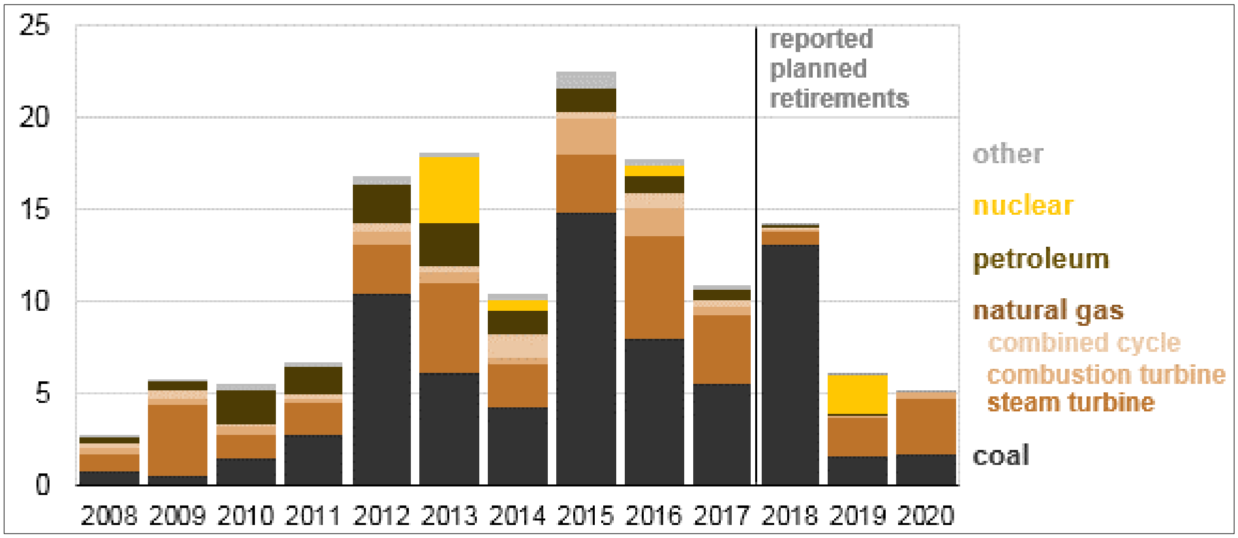

Figure 2-1 U.S. Utility-scale Electric Generating Capacity Retirements (2008-2020), Gigawatts

Source: EIA, Today in Energy (December 19, 2018)

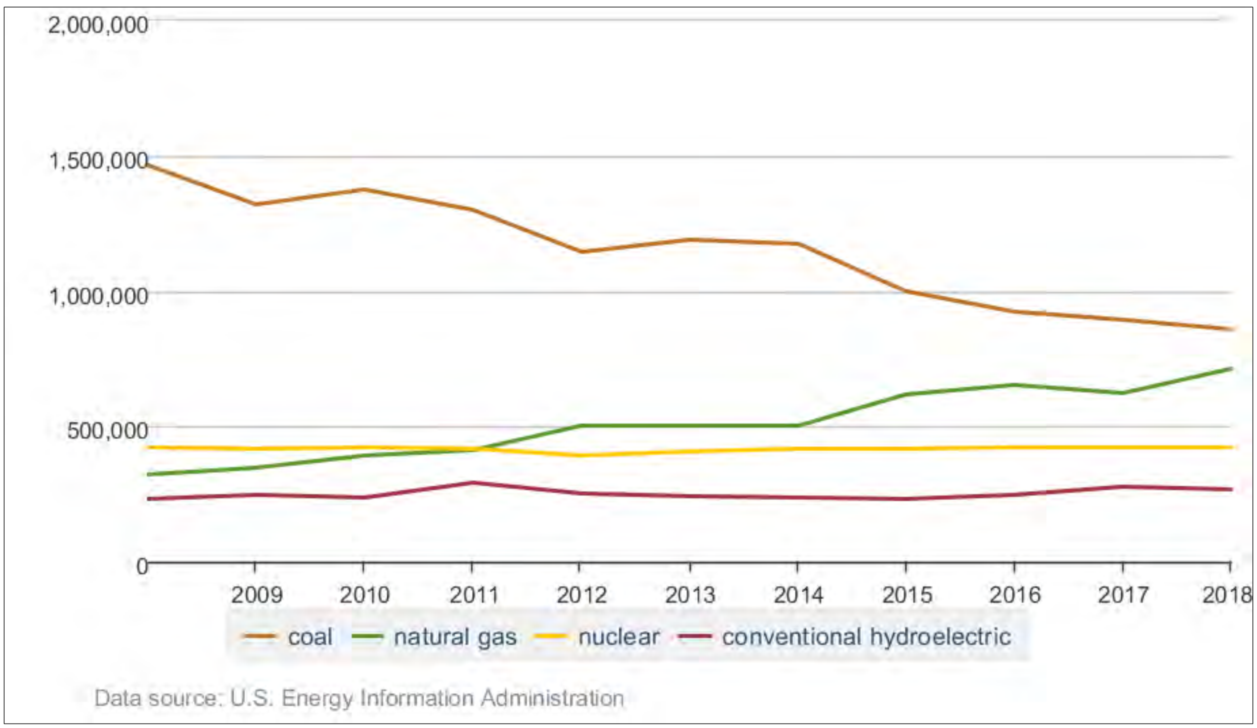

Figure 2-2 Net Generation, United States, Electric Utility, Annual (thousand megawatthours)

Source: EIA Electricity Data Browser

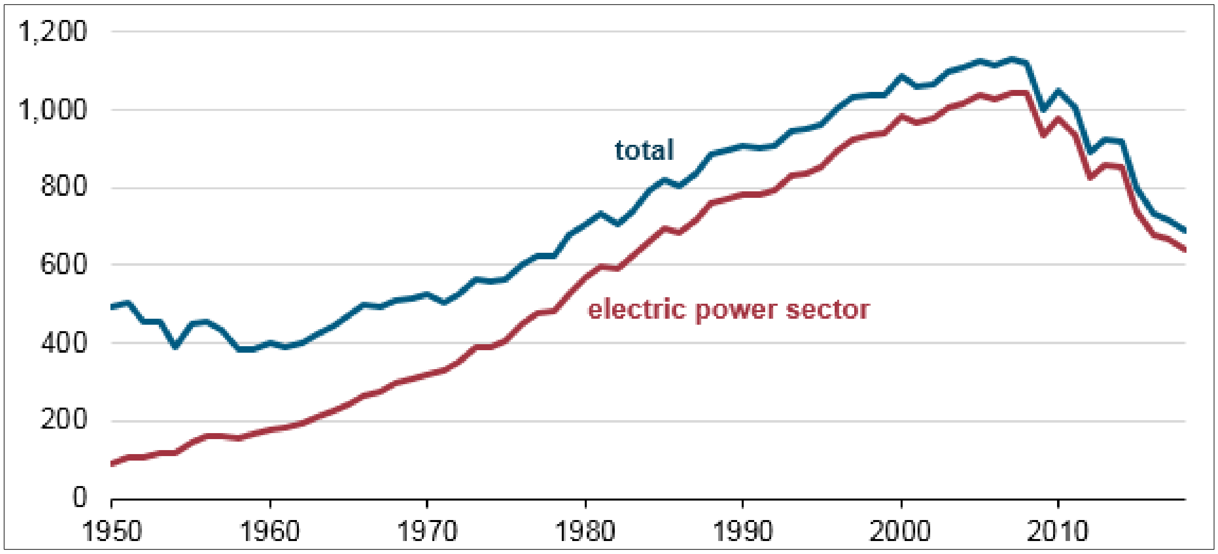

Figure 2-3 U.S. Coal Consumption (1950-2018) (million short tons)
Source: EIA[9]

2.2.1.2 Natural Gas Supply and Price Trends

Technological advances in the natural gas industry have led to an abundance of natural gas supply, resulting in a highly competitive (low price) fuel supply that is increasingly being relied upon by the power sector, particularly as new pipeline infrastructure continues to be built across the country. U.S. natural gas production hit a new record in 2018, with both the highest volume and largest annual increase in production on record.[10]

[9] EIA, Today in Energy (December 28,2018), *available at* https://www.eia.gov/todayinenergy/detail.php?id=37817.
[10] EIA, Today in Energy (March 14, 2019), *available at* https://www.eia.gov/todayinenergy/detail.php?id=38692.

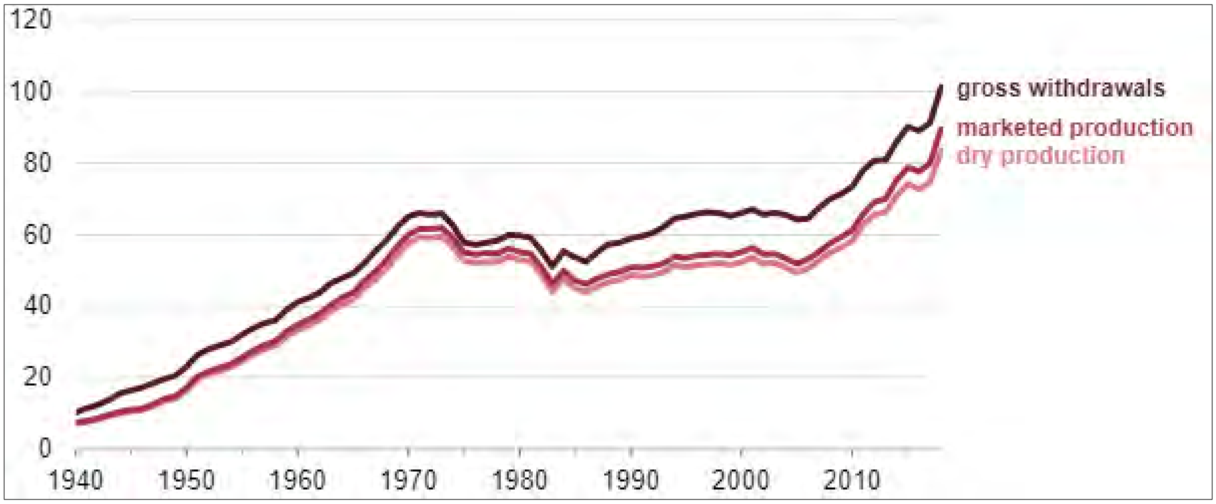

Figure 2-4 U.S. Annual Natural Gas Production (1940-2018) (billion cubic feet per day)
Source: EIA[11]

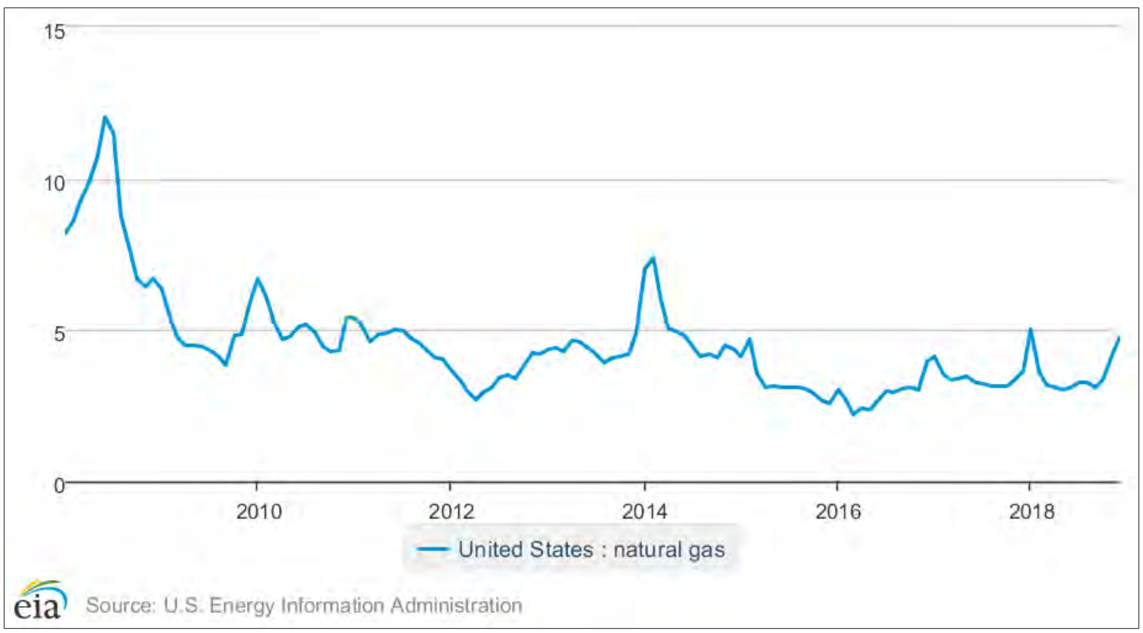

Figure 2-5 Average Cost of Fossil Fuels for Electricity Generation (per Btu) for All Sectors, Monthly (dollars per million Btu)
Source: EIA, Natural Gas Monthly Report

[11] EIA, Today in Energy (March 14, 2019), *available at* https://www.eia.gov/todayinenergy/detail.php?id=38692.

2.2.1.1 Renewable Energy

The costs of renewable generation have fallen significantly due to technological advances, improvements in performance, and local, state, and federal incentives such as the recent extension of federal tax credits.[12] According to Lazard, a financial advisory and asset management firm, current unsubsidized levelized cost of electricity for alternative energy technologies is lower than the operating cost alone of conventional technologies like coal or nuclear, which is expected to lead to ongoing and significant deployment of renewable energy. Levelized cost of electricity is only one metric used to compare the cost of different generating technologies. It contains a number of uncertainties including utilization and regional factors.[13] While this chart illustrates general trends, unit specific build decisions will incorporate many other variables.

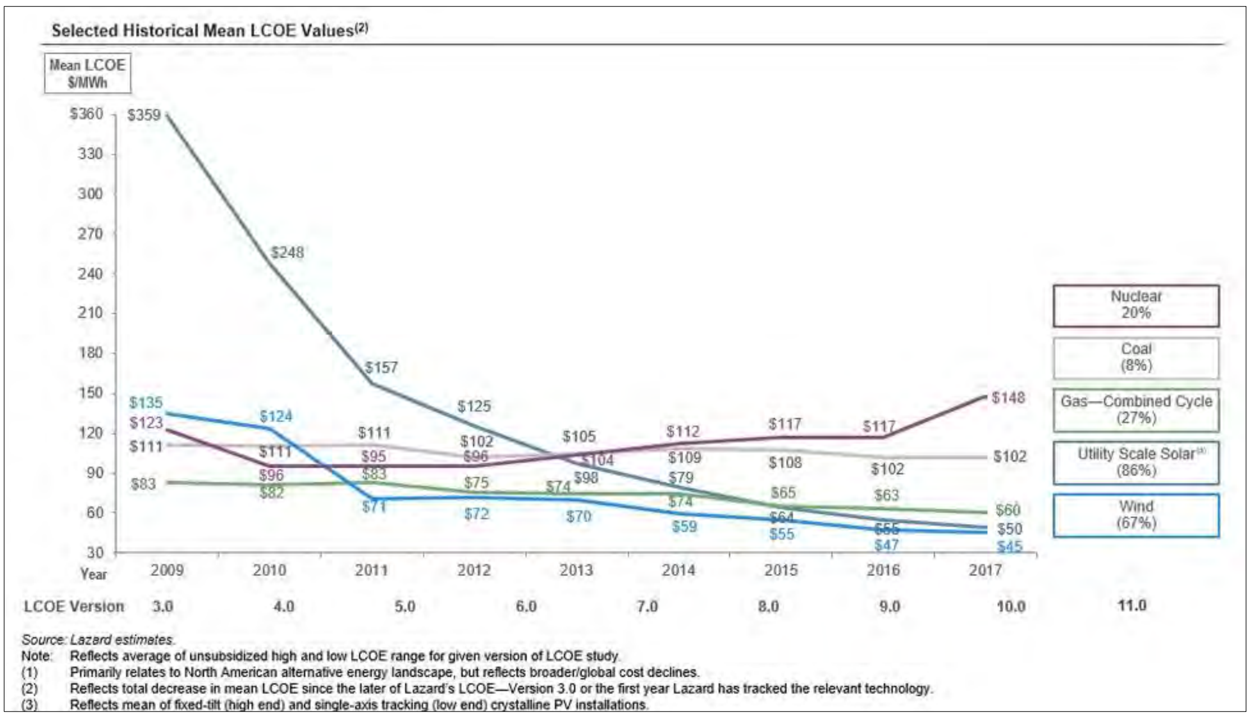

Figure 2-6 Selected Historical Mean LCOE Values

Source: Lazard, Levelized Cost of Energy 2017

As a result, the existing coal fleet continues to experience economic pressures. The cost trends, along with other developments, have served as the main drivers for pronounced, ongoing changes in the nation's generation mix that have resulted in lower CO_2 emissions.

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[12] Lazard, Levelized Cost of Energy 2017. https://www.lazard.com/perspective/levelized-cost-of-energy-2017/

[13] U.S. Energy Information Administration, 2019. https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf

2.2.2 Utility Climate and Clean Energy Announcements and Commitments

The broad trends away from coal-fired generation and toward lower-emitting generation are reflected in the recent actions and recently announced plans of many power plants across the industry — spanning all types of companies in all locations. Furthermore, many utilities have made commitments to move toward cleaner energy. Throughout the country, utilities have included commitments towards cleaner energy in public releases, planning documents, and integrated resource plans (IRPs). For strategic business reasons, most major utilities plan to increase their renewable energy holdings and continue reducing CO_2 emissions, regardless of what federal regulatory requirements might exist. The Edison Electric Institute (EEI) has confirmed these developments: "While the CPP was stayed by the Supreme Court in 2016, the power sector will have complied with the final 2030 goals of the rule—in terms of gross emissions reductions—before the 2022 start date included in that program."[14] This trend is not unique to the largest owner-operators of coal-fired generation; smaller utilities, public power, cooperatives, and municipal entities are also contributing to these changes.

There are many recent examples of electric utilities who have publicly announced near- and long-term emission reduction commitments. Here are but a few examples of emission reduction targets of 80%+ (relative to 2005 levels) that have recently been announced by major utilities:

- Xcel Energy (with power plants that operate in MN, CO, MI, MN, NM, ND, SD, TX, and WI): 50% reduction in CO_2 emissions by 2022 (and 100%) and carbon-free by 2050)[15] This includes a commitment to close all coal plants in Minnesota by 2030[16]

- DTE Energy (MI): 30% reduction in CO_2 by the early 2020s, 50% by 2030, 80% by 2040 and 80%+ by 2050[17] (these goals were recently accelerated)[18]

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[14] EEI Comments on ACE, at 4 (Oct. 31, 2018).
[15] Xcel Energy, Integrated Resource Plan(s), *available at* https://www.xcelenergy.com/environment/carbon_reduction_plan.
[16]https://www.xcelenergy.com/company/media_room/news_releases/xcel_energy_to_end_all_coal_use_in_the_upper_midwest
[17] DTE Energy, IRP (under public review), *available at* http://newsroom.dteenergy.com/index.php?s=26817&item=137217#sthash.6EU4Hz0y.mSpR9OKB.dpbs.
[18] http://newsroom.dteenergy.com/2019-03-28-DTE-Energy-accelerates-carbon-reduction-goal-a-full-decade-will-reduce-emissions-80-percent-by-2040#sthash.UY40RqAg.dpbs

- Ameren Energy (MO): 35% by 2030, 50% by 2040, and 80% by 2050[19]
- Consumers Energy (MI): 80% by 2040 and transition to zero coal use[20]
- MidAmerican Energy (IA): 100% RE goal[21]
- NIPSCO (IN): 90% reduction by 2028, and phase-out all coal[22]
- First Energy (FE): 90% reduction by 2045[23]
- American Electric Power (AEP): 60% reduction by 2030 and 80% by 2050[24] (from year 2000 levels)
- Alliant Energy: 40% reduction by 2030 and 80% by 2050[25] and phase-out all coal
- WEC Energy Group: 40% reduction by 2030 and 80% by 2050[26]

While the EPA does not account for statements from utilities regarding their future plans in the economic modeling that are not technically legally enforceable, the number and scale of these announcements is significant on a systemic level. These statements are also part of long-term planning processes that cannot be easily revoked, since there is considerable stakeholder involvement, including by regulators, in the planning process. The direction in which these companies have publicly stated they are moving is consistent across the sector and undergirded by market fundamentals lending economic credibility to these commitments and confidence that there is a high likelihood that most will be implemented. Thus, these announcements are sufficiently consequential to be considered in identifying the appropriate economic baseline.

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[19] Ameren Missouri, Integrated Resource Plan, *available at* https://www.ameren.com/missouri/company/environment-and-sustainability/integrated-resource-plan.
[20] Consumers Energy IRP, *available at* https://www.consumersenergy.com/community/sustainability/energy-mix/renewables/integrated-resource-plan.
[21] MidAmerica Energy, Our 100% Renewable Vision, https://www.midamericanenergy.com/our-renewable-energy-vision.aspx.
[22] NIPSCO IRP, available at https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/irp/2018-nipsco-irp.pdf?sfvrsn=15
[23] First Energy, available at https://firstenergycorp.com/content/fecorp/environmental/initiatives.html
[24] AEP, available at https://www.aep.com/news/releases/read/1503/AEPs-Clean-Energy-Strategy-Will-Achieve-Significant-Future-Carbon-Dioxide-Reductions
[25] Alliant Energy, available at https://sustainability.alliantenergy.com/energy-climate/
[26] WEC Energy, available at https://www.wecenergygroup.com/csr/climate-report.pdf

2.2.3 Recent Emissions Trends & Future Projections

The aforementioned market trends and business decisions have resulted in declining power sector CO_2 emissions since 2005, which are also expected to produce a notably lower emissions future as higher emitting sources of electricity are replaced with lower-emitting sources. In 2012, aggregate CO_2 emissions from sources covered by the CPP were 19 percent below 2005 levels. When the EPA finalized the CPP in August 2015, the Agency projected that, by 2030, the power sector would reduce its CO_2 emissions 32 percent below 2005 levels with the CPP. By the end of 2015, several months after the CPP was finalized, those sources already had achieved CO_2 emission levels 24 percent below 2005 levels, in the aggregate. Even after the CPP was stayed, in 2016, sources were 28 percent below 2005 levels. In both 2017 and 2018 sources were 30 percent below 2005 levels.[27]

The evolution of these overarching power sector trends can be seen in the EIA's Annual Energy Outlook (AEO), which includes energy projections of the future. The AEO includes a CO_2 projection in a baseline scenario, similar to the EPA's baseline projections using IPM, which show how these trends have been absorbed into the AEO over time (see Figure 2-7). Figure 2-7 also demonstrates the extent to which recent power sector modeling has consistently tended to under-estimate the degree of CO_2 projected in the future. If the current trendline in this figure continues, power sector emissions will be well below the original 2022 and 2030 aggregate mass-based goals in the CPP, marked by "Xs" in the graph.

[27] EPA, Air Markets Program Data (affected sources under CPP), *available at* https://ampd.epa.gov/ampd.

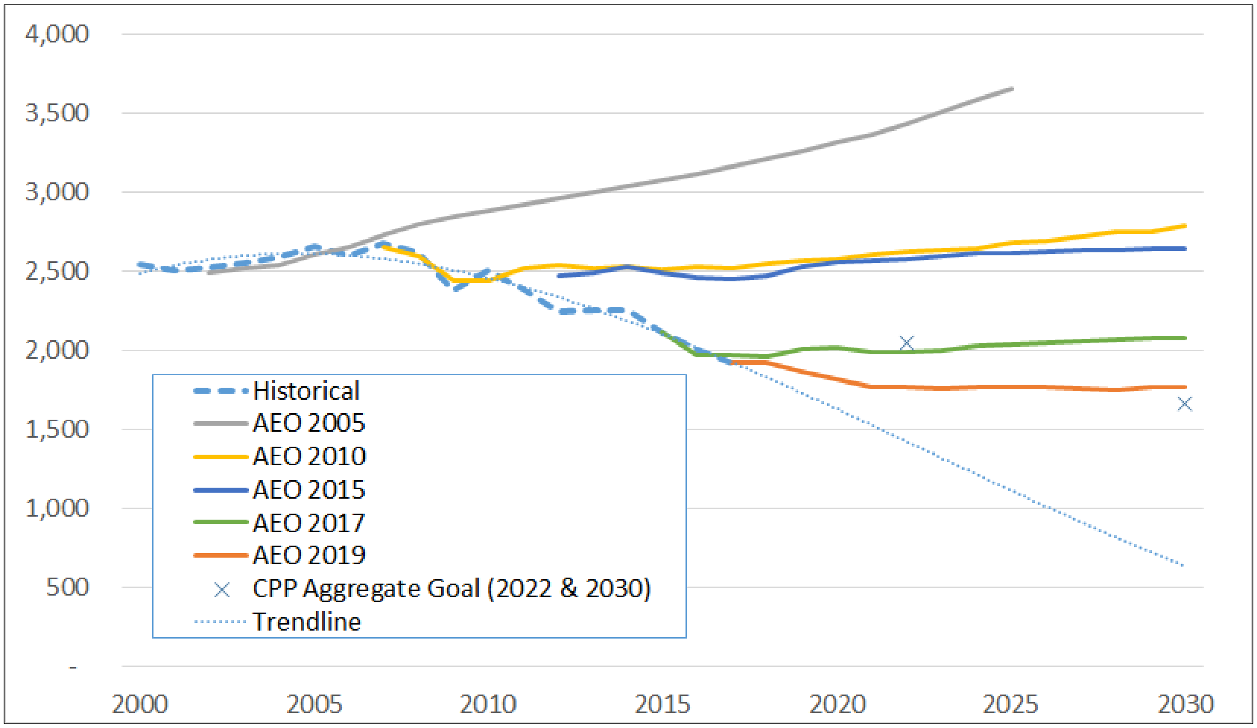

Figure 2-7 Power Sector CO_2 Emissions (million short tons)

Source: EIA AEO, and EPA for CO_2 data (AMPD database).

For example, the AEO estimates from 2005 and 2010 were just prior to the large domestic expansion of gas supplies. Also, while renewable energy was being deployed in that time period, it was on a much smaller scale and at a cost not nearly as competitive as it is today. As such, there was an expectation of continued generation from coal-fired sources for the foreseeable future. Only after 2015 did the AEO begin to more concretely factor these trends into the projections, which can be seen in the notable decline in the CO_2 emissions projection. The most recent AEO, for 2019, shows CO_2 emissions significantly lower than the AEO from four years earlier (2015). As Figure 2-7 demonstrates, each successive AEO projection has suggested that CO_2 emissions would either flatten or decrease from previous iterations of the AEO, and has been continually revised downward following the trendline of the historical data.

2.3 CPP Stay/Delayed Implementation and Trading Assumptions

The implementation timing of the CPP, and the manner in which it would be implemented, are no longer valid due to changed circumstances since the CPP was finalized in

2015. These changes, in conjunction with the trends discussed above, have further weakened the effect the CPP was previously anticipated to have relative to a no-CPP baseline.

2.3.1 Delayed implementation of the CPP

The Supreme Court issued a stay of the CPP in February of 2016, effectively pausing the rule during judicial review. The litigation challenging the CPP has been held in abeyance since 2017, when the EPA announced its intentions to reconsider and potentially repeal the CPP. Given the resulting delay in implementation already to-date, the timing of reduction requirements under the CPP, as it was finalized in 2015, is no longer reasonable to assume, since states and sources have been under no obligation to plan for or to implement the rule. In a hypothetical world where CPP comes back into effect, its deadlines for compliance would likely require adjustment.

Under the original schedule for CPP implementation, state plans were due in September of 2018 at the latest. The first compliance period was scheduled to begin in 2022. Subsequent compliance periods, corresponding with increasingly stringent state goals would have run from 2025-2027, and 2028-2029, with final CPP goals going into effect in 2030. Two-year compliance periods would have run perpetually from 2030 with no further change in stringency.

The deadline for state plan submittals in 2018 has already passed. Thus, the start of the initial compliance period would unlikely be 2022, as originally promulgated in the CPP, since States have been under no obligation to develop and submit state plans to implement the program since it was stayed. As such, for purposes of this analytical exercise, an appropriate implementation time horizon for CPP would involve adjusting the compliance deadlines, possibly by delaying them for several years.[28] Over three years have passed since the stay was issued, which is a logical starting point when considering a tolling timeframe. Hence, the EPA considers a three-year delayed implementation of CPP as a reasonable starting point when

[28] Although not determinative, a similar period of tolling was the result in the Cross-State Air Pollution Rule (CSAPR) litigation, where roughly three years elapsed between the D.C. Circuit Court of Appeals' stay of the rule and its order granting EPA's motion to lift the stay. *See* Order, Document #1518738, *EME Homer City Generation, L.P. v. EPA*, No. 11-1302 (D.C. Cir. issued Oct. 23, 2014); Interim Final Rule, 79 Fed. Reg. 71663 (Dec. 3, 2014); Final Rule, 81 Fed. Reg. 13275 (March 14, 2016). And a similar approach to tolling was taken in lifting the stay of the NO_X SIP Call. Order, *Michigan v. EPA*, No. 98-1497 (D.C. Cir. issued June 22, 2000).

considering a hypothetical implementation of that rule.[29] For purposes of the EPA's updated modeling in this analysis, we assume that CPP compliance commences in 2025, with final goals going into effect beginning in 2033.This serves to further diminish the effect of the CPP, since the later it is implemented the more likely that market trends will have already resulted in emissions that are lower than the CPP goals. Furthermore, in a mass-based implementation scenario, with emissions already generally below the goals for the first compliance period (starting in 2025), there will be more allowances available to be banked for use in subsequent compliance periods than there otherwise would have been without tolling the deadlines.

To demonstrate the effect of delaying implementation of the CPP, in the maps below, State-level emissions from existing sources are shown in two ways. The first map shows emissions for each state from the baseline projection (i.e. a scenario with no 111(d) CO_2 requirement for existing EGUs) for the year 2030, relative to each state's respective mass-based goal for CPP for 2030 (prior to any consideration of implementation delay for CPP). Positive values indicate that a state's projected baseline CO_2 emissions in the baseline projection are lower than the state-level CPP goal (i.e., the state's emissions in 2030 are below the 2030 goal), while negative values indicate that a state's emissions in the baseline in 2030 are higher than the goal. It should be noted that these values from the baseline are conservative in light of additional long-term changes in the generation mix (e.g., coal plant retirements and utility announcements) that have been announced or included in IRPs since this modeling was performed, as discussed in Section 2.2.3 above. In other words, the shortfalls in emission reductions apparently facing some states are in all likelihood smaller than the numbers below suggest, and again, these figures do not factor in any delay in CPP implementation.

[29] The EPA does not intend for this hypothetical scenario for implementation of the CPP to reflect or imply a binding commitment at this stage to adjust deadlines in this manner for the CPP in the unlikely event that it would be implemented. Such a determination would require a full analysis of all the facts and circumstances at the time such a determination would need to be made.

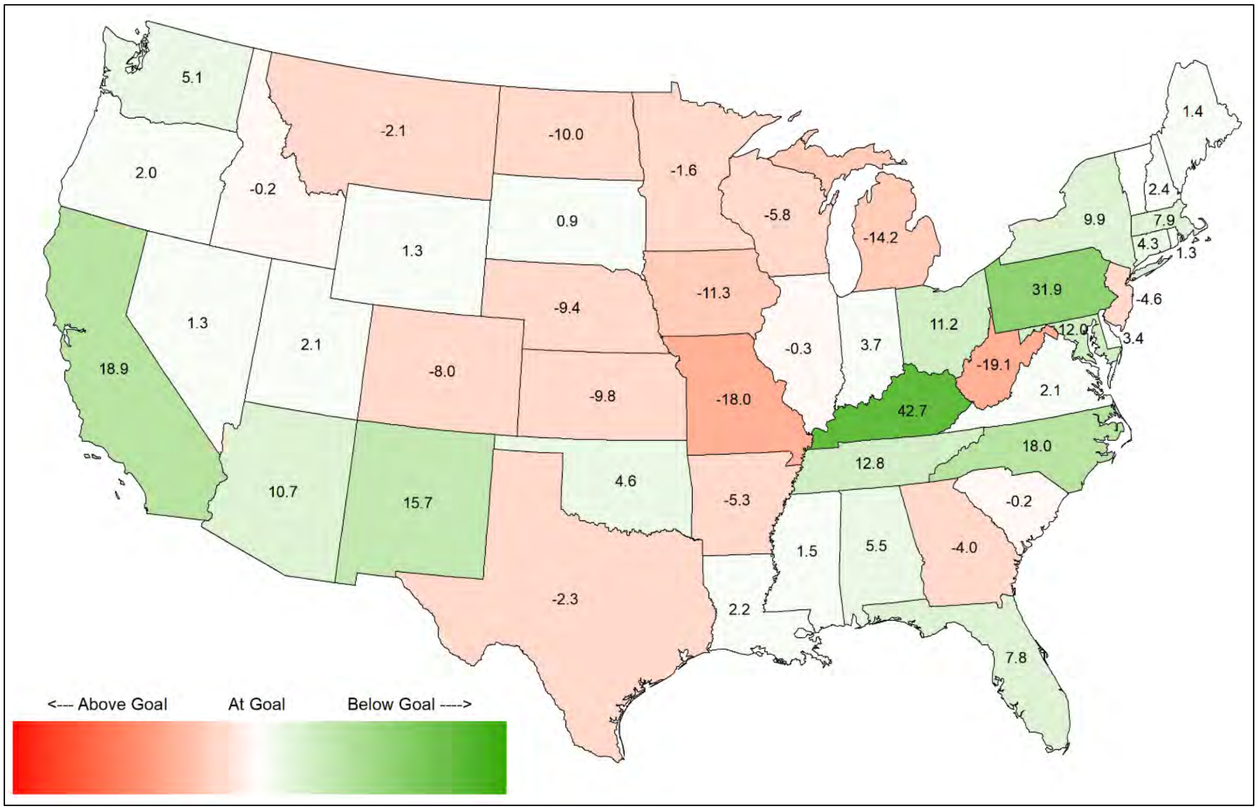

Figure 2-8 State-Level CO_2 Short Tons Emissions Comparison: Baseline Emissions vs. CPP Goals for 2030

Source: EPA, State-level goals for CPP and baseline projections of CO_2 from IPM.

The second map shows data in a similar manner, but uses baseline emissions from 2025 (instead of 2030) and compares the annual CPP goals for the interim compliance period beginning in year 2022. This comparison is intended to show how a three-year delayed implementation of CPP would appear, relative to the baseline projection in the initial year of the program. This comparison shows even more states with emissions in the baseline below the CPP goals, and fewer states above the goal (as well as the potential number of allowances that are available for compliance in later years). Collectively, all states taken together are considerably below the goals.

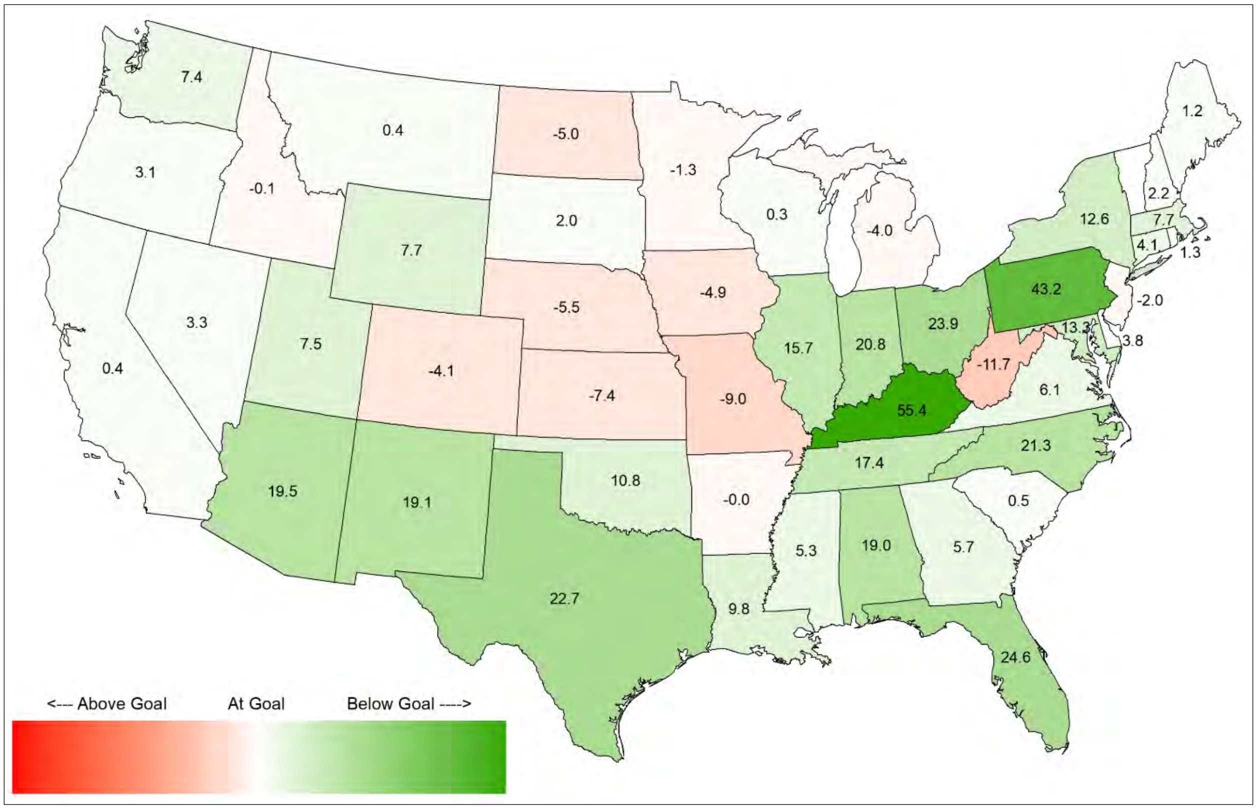

Figure 2-9 State-Level CO_2 Short Tons Emissions Comparison: Baseline Emissions in 2025 vs. CPP Goals for 2022

Source: EPA, State-level goals for CPP and baseline projections of CO_2 from IPM.

2.3.2 Interstate Trading under the CPP

The CPP provided significant flexibility to States to meet their goals and allowed for multiple compliance pathways for implementing the rule. In particular, interstate mass-based trading was of interest to many states and sources. To facilitate efficient and flexible implementation of the CPP, the EPA released draft Model Trading Rules language in 2016 to assist States as they considered possible compliance pathways. Emissions trading systems allow for compliance with an overall emissions limit or goal by allocating or auctioning emissions allowances (equal to the overall budget or goal) to emitting sources. Sources must surrender allowances equal to their emissions for that period, thus ensuring that total emissions are no more than the goal expressed as an emissions budget. This system can be implemented at the State level, i.e., without interstate trading, which was represented in the RIA for the final CPP (2015) and subsequent representations of the CPP (2018 ACE Proposed Rule RIA, 2017 CPP repeal

RIA and in this Chapter). The assumed implementation of trading at the state-level in the 2015 final CPP RIA was determined to be most appropriate to demonstrate that each state could meet the goals cost-effectively, even without the assumption of broader trading.[30]

The EPA did not analyze interstate trading scenarios at the time it promulgated the CPP, even though the EPA encouraged states to join multi-state plans to increase compliance flexibility. This increased compliance flexibility may lead to lower CO_2 reductions. Applying Circular A-4's guidance that the baseline used in an analysis "should be the best assessment of the way that the world would look absent the proposed action," and because the analysis is no longer being used to make a regulatory decision that could be impacted by consideration of the CPP on individual states, the EPA believes it is appropriate to revisit this approach and assess interstate trading scenarios under the CPP.

There is a significant history of states using interstate trading when such flexibility is allowed (e.g., such opportunities were generally welcomed by states or implemented by them directly in the NOx SIP Call, CAIR, CSAPR and WRAP). There was significant interest amongst a broad and diverse set of stakeholders during the CPP rulemaking who advocated for allowing such implementation flexibility. Such a scenario would still be as reasonable to assume as no interstate trading, and in fact represents a more likely CPP implementation scenario. Stakeholders and commenters to the EPA have consistently sought compliance flexibility through averaging or trading programs, which the CPP explicitly allowed. Many industry and state commenters on ACE again sought for the EPA to allow broad-based trading options as a flexible means of implementation of a section 111(d) program for the power sector.[31]

The EPA has now modeled and analyzed a new CPP scenario with IPM to help shed light on a potential interstate-trading compliance scenario (coupled with a three-year delay in implementation). Another possible implementation of CPP is sub-national, regional trading. To shed light on possible quantitative effects of these alternatives, the EPA has conducted additional modeling, as described below. As noted elsewhere in this chapter, the EPA has also modeled the CPP again for purposes of the final ACE rule, with no interstate trading and without any

[30] See CPP Final Rule RIA (2015), Chapter 3 for more detail.
[31] *See, e.g.,* EEI Comments on ACE, at 22 (Oct. 31, 2018); UARG Comments on ACE, at 73-75 (Oct. 31, 2018); Texas CEQ Comments on ACE, at 8 (Oct. 31, 2018); Pennsylvania DEP Comments on ACE, at 8 (Oct. 31, 2018).

consideration of delayed implementation of CPP in order to provide the public with the ability to understand the analysis in a manner consistent with previous CPP modeling.

2.3.2.1 National Trading

The EPA has looked at the impacts of interstate trading in two ways. First the agency has done new CPP modeling essentially assuming nation-wide trading combined with a three-year implementation delay.[32] Second, the agency modeled regional trading and used information from state-level goals and baseline modeling to explore the impacts of regional trading.

The nation-wide trading scenario allows for greater flexibility across sources and States (i.e., interstate trading) and assumes delayed implementation timeframes as described previously (i.e., compliance beginning in 2025 and final goals taking effect in 2033). In this scenario, sources must collectively comply with a national-level mass-based CPP emission target. The CPP scenarios included in this chapter focus on mass-based implementation due to the relative ease of modeling mass (vs. rate) in the model. In addition, the rate-based and mass-based forms of implementation of the CPP goals were included to provide flexibility and specifically designed to produce equivalent levels of stringency. All of the numeric values, data, and formulas used for establishing goals under CPP were developed with a consistent framework.

As the more detailed results in section 2.7 show, this scenario results in almost no impact from the CPP. A CPP scenario that allows for broader trading, when implemented in IPM, shows that the CPP has no impact because business-as-usual industry trends result in emission levels at the national scale that are already within the collective state budgets of the CPP under this form of implementation. While there are very small changes in costs (less than \$5 million nationwide in any given year), there are no changes in CO_2 emissions. In other words, when modeled, this scenario produces essentially the same outcomes as the baseline scenario.[33] This supports the conclusion that CPP would likely have little or no impact.

[32] California and the states that comprise the Regional Greenhouse Gas Initiative were excluded from the national CPP trading scenario; the state requirements from those existing programs were kept in place, and the CPP goals for CA and RGGI were met independently without trading (CPP goals were non-binding).
[33] For more detail on these scenarios, see Addendum.

2.3.2.2 Regional Trading

The EPA has also modeled an IPM scenario with regional (i.e., sub-national) trading using six smaller hypothetical trading regions. Based on discussions that states were having prior to the stay of CPP, EPA believes that some level of regional trading would have been the most likely outcome of CPP implementation. The regions that the EPA examined are roughly based upon a combination of the North American Electric Reliability Corporation regional alignment for the U.S. and Regional Transmission Organizations (RTO)/Independent System Operators (ISO) regions.[34] NERC is tasked with ensuring the reliability of the North American bulk power system, while RTO/ISO boundaries help facilitate organized wholesale electricity markets (see Figures 2-10 and 2-11).

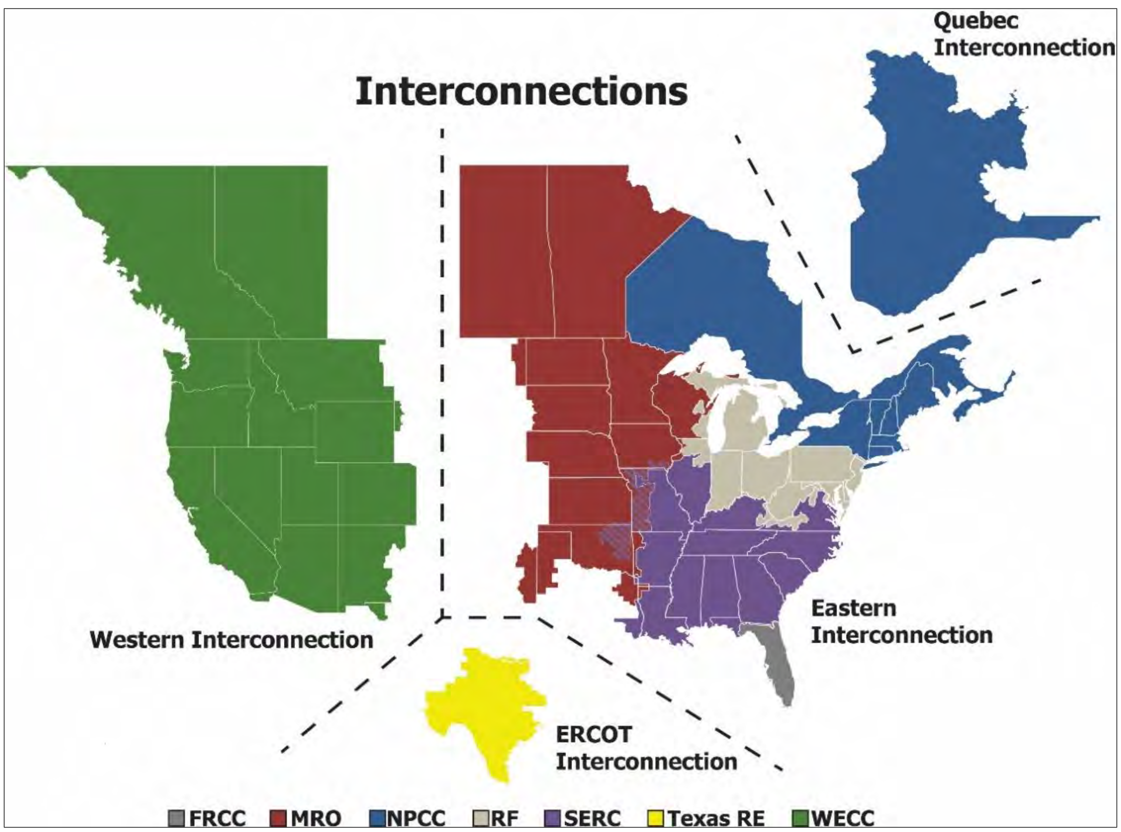

Figure 2-10 NERC Interconnections
Source: North American Electric Reliability Corporation

[34] https://www.nerc.com/AboutNERC/keyplayers/pages/default.aspx and https://www.ferc.gov/industries/electric/indus-act/rto.asp

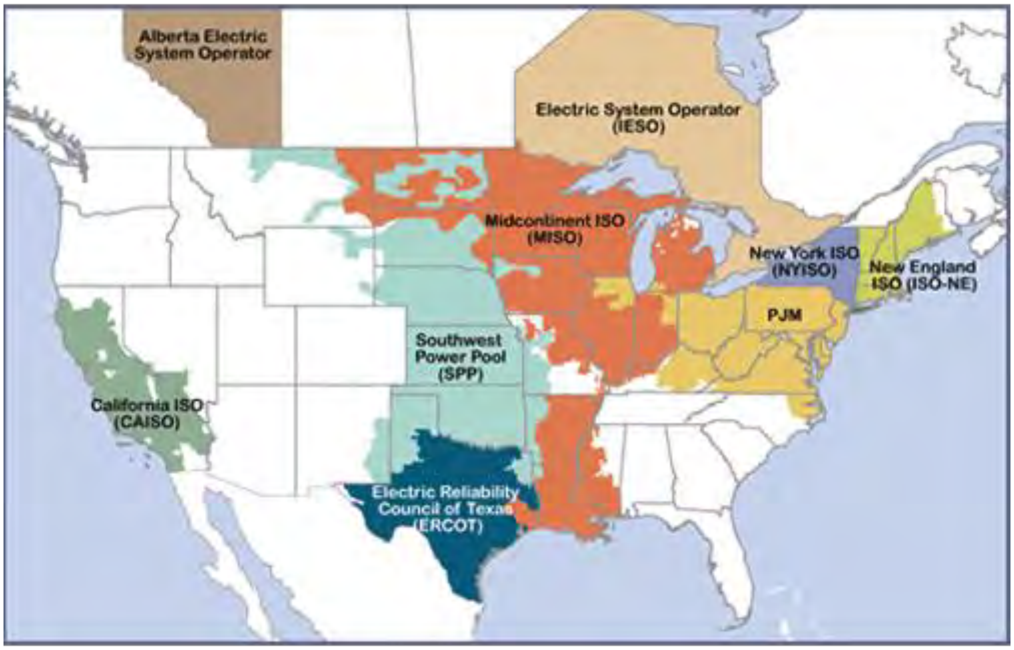

Figure 2-11 RTO/ISO Regions
Source: Federal Energy Regulatory Commission

Groupings of states were then determined based upon the rough boundaries of electricity markets (i.e., NERC and RTO/ISO regions) and state borders, which do not always conform. All states are assumed to join a regional trading grouping to take advantage of greater compliance flexibility, even when it fully encompasses an RTO/ISO or NERC region (i.e., ERCOT and FRCC), unless there was an existing GHG regulatory structure already in place[35] (i.e., California). Furthermore, some states were grouped into trading regions that extend over multiple RTO/ISO or NERC regions, in particular where power markets are not coterminous with state borders (e.g., Central and Midwest states). The resulting six regions, as shown in the map below, are used as the basis for an illustrative CPP scenario with regional trading. This scenario also includes delayed implementation, as previously discussed.

[35] States in RGGI were grouped into a single region for this same reason.

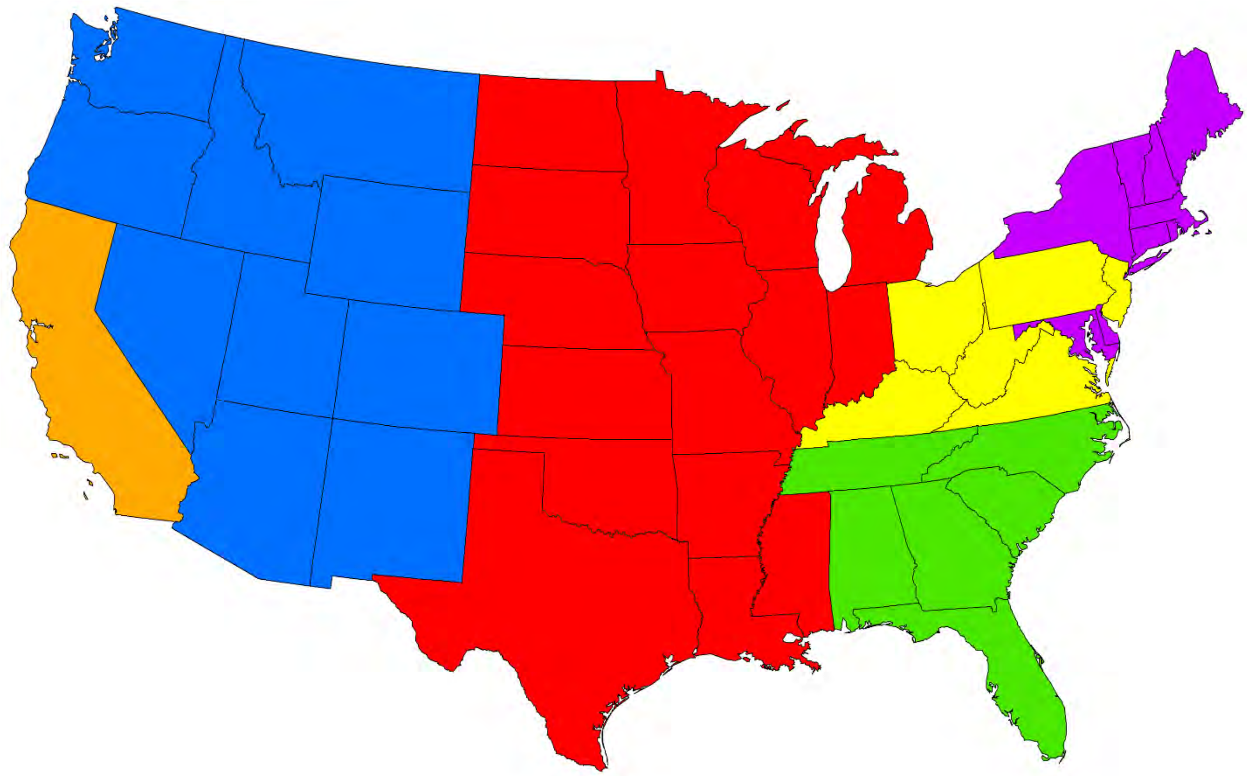

Figure 2-12 CPP Trading Regions: PJM (yellow), Southeast (green), Northeast/RGGI (purple), Midwest/Central (red), West (blue), and California (orange)

This scenario yields very small impacts, and the collective regional CPP goals require CO_2 emission reductions beyond the baseline for only one region (the Midwest/Central region). This hypothetical regional trading scenario would result in compliance with the CPP goals with no additional effort, except for one region. In addition, the CPP is only minimally binding in that region, with a marginal cost of less than $1/ton of CO_2. The marginal cost for all other regions is zero. Table 2-2 presents national CO_2 emissions changes and Table 2-3 presents compliance costs, which is the increase in system-wide generation costs, for the CPP with Regional Trading and Tolling relative to a baseline with no 111(d) requirement for existing EGUs.[36]

In addition to the regions chosen for this illustrative scenario, there are a variety of alternative regional trading groupings that would result in compliance with the CPP targets with little or no additional effort, if modeled. Further, even if some regions faced a shortfall, it is reasonable to anticipate that utilities in those regions could easily take steps to avoid any

[36] These costs do not include costs for monitoring, reporting, and recordkeeping.

meaningful impact of a CPP emissions budget. Any administrative boundaries for the hypothetical trading groups don't constrain the flow of electricity. Generation will, in part, shift to where the mass-based goals are already below the CPP budget in a business as usual, and therefore existing fossil generation will increase in other regions in response to emission reductions in regions with a shortfall.

Table 2-2 Projected CO_2 Electric Sector Emission Impacts, Relative to Baseline

	CO_2 Emissions (MM Short Tons)			CO_2 Emissions Change (MM Short Tons)			CO_2 Emissions Change Percent Change		
	2025	2030	2035	2025	2030	2035	2025	2030	2035
Baseline	1,774	1,743	1,719						
CPP with Regional Trading and Tolling	1,767	1,733	1,709	-8	-10	-10	-0.4%	-0.6%	-0.6%

Table 2-3 Annualized Compliance Costs, Relative to Baseline (millions of 2016$)

	2025	2030	2035
CPP with Regional Trading and Tolling	-$32	$27	$139

Additional information is presented below for the Midwest/Central region in order to provide more context, since it is the only binding region from the Regional Trading and Tolling scenario. Figure 2-13 presents the historical CO_2 emissions from affected sources in the Midwest/Central region, and compares regional CO_2 emissions projections from the previous baseline projection (used in 2015 when CPP was finalized) to the current baseline from this Final ACE rule. This figure also shows the regional CPP goals for the Midwest/Central Region that are reflected in the Regional Trading scenario, although the figure does not show the goals being tolled (3 years). First, the figure demonstrates how much lower baseline emissions are now projected to be for this region than they were in 2015, due to the ongoing trends and changes in the electric power sector. Second, the data shows that the current baseline emissions projections are very close to the goals, and only a modest amount of additional reductions would be necessary to meet the regional goals (indeed, the projected marginal cost of doing so is less than $1/ton CO_2). Third, the baseline projections should be considered in the context of the recent utility and announcements that are not reflected in the baseline, which were mentioned earlier in this chapter. These long-term planning announcements from utilities in this region, if realized, would reduce baseline emissions well below the CPP goals shown in the figure.

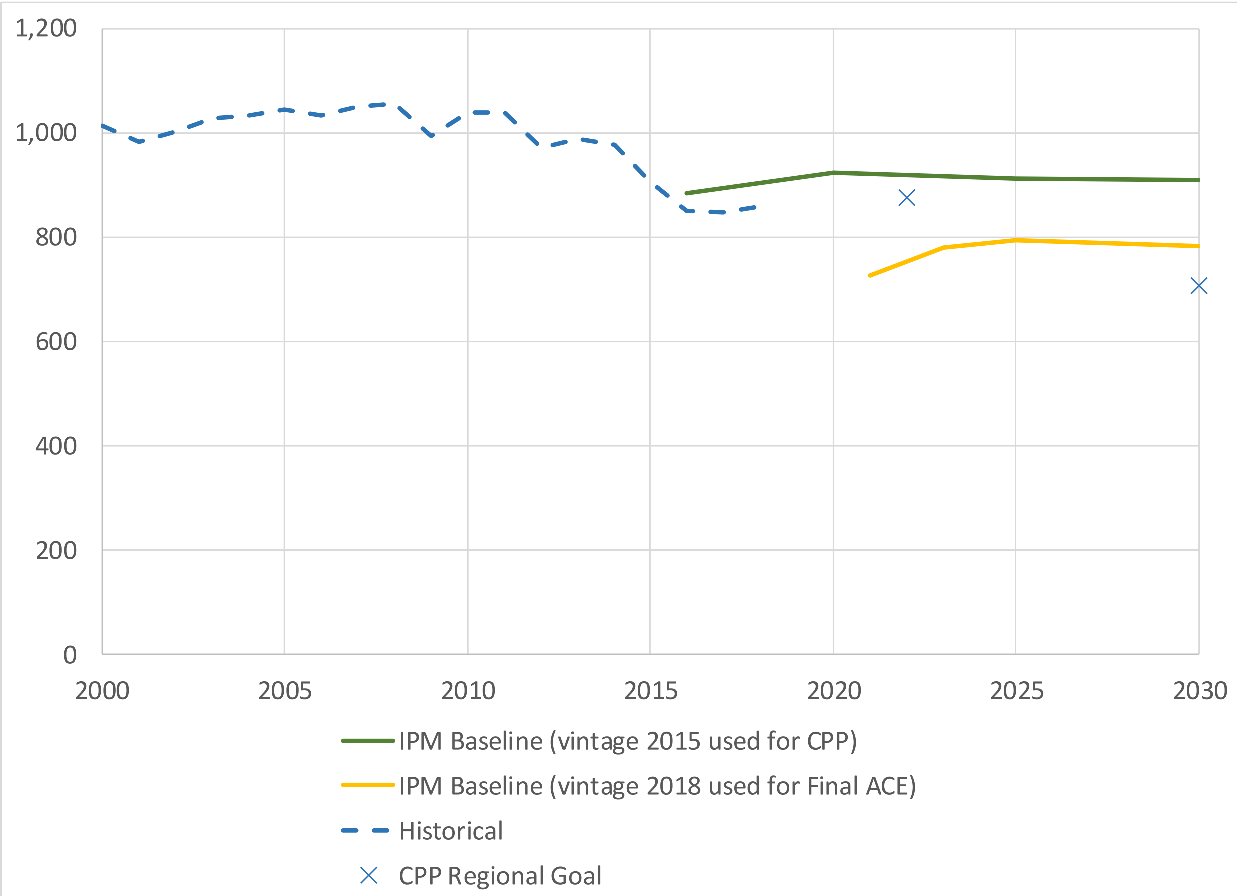

Figure 2-13 CO_2 Emissions for the Midwest/Central Region: Historical and Baseline Projections from IPM (million short tons)

Figure 2-13 also shows that the previous baseline projections for the Midwest/Central region were well above the regional CPP goals, while the updated modeling projects emissions to be well below the CPP goals prior to 2030 for this region. This highlights the dramatic changes underway in the industry. More specifically, the previous modeling projected baseline emissions to be roughly 4 percent above the 2022 CPP goal, while the updated modeling projects emissions in this region to be 11 percent below the 2022 CPP goal. In 2030, affected sources are projected to further reduce CO_2 emissions significantly in the updated modeling, making 63 percent of the reduction merely under baseline conditions (comparing the deficit in 2030 from previous projections to the remaining deficit in the current projections). It is important to note that the baseline does not necessarily include all the numerous commitments that major utilities have announced and are planning in this particular geographic region (also discussed earlier in this chapter). These activities are partially quantified below, for additional context.

Several large investor-owned electric utilities have made long-term decarbonization commitments across their respective generating fleets in the Midwest/Central region, and have also recently accelerated these plans due to continually evolving market dynamics. Some of these commitments are not included in the projected baseline, but it is possible to estimate the emissions implications attributable to these kinds of commitments in a simple manner (because banking is not accounted for in this static analysis looking solely at the impact of the retirements in a single year, the true impact may be understated since some of these newly announced retirements occur before 2030, they allow for additional banking of allowances). EPA's current modeling assumes operation of these units post 2030, such that removal of those units based on utility plans not only reduces the emissions shortfall, but also reduces the demand for allowances. The subsequent data focuses on utilities that have announced longer-term goals with specificity, with regards to particular power plants that will be removed from service by 2030, and is only a partial list. In the recent reference case, some of these units are projected to emit roughly 31 million tons of CO_2 in 2030 (these estimates are not incorporated into the modeled emissions projections shown in Table 2-2).[37] This accounts for over 40 percent of the difference between the baseline emissions in 2030 compared to the CPP goals for the Midwest/Central region (the difference between the "X" and the yellow line on Figure 2-13). These particular CO_2 emission reduction estimates that are not in the baseline, along with the other non-quantified reductions that are anticipated, lead EPA to believe that CPP would be non-binding in the Midwest/Central region. Removing these units from service will result in reductions of criteria pollutants and toxic emissions, in addition to the CO_2 emissions reductions that are planned. It is also important to note that the CPP scenario with regional trading and tolling resulted in a

[37] IPM Reference Case parsed file for 2030, CO_2 emissions for the following operating power plants: Allen S. King, Belle River, Dan E Karn, JH Campbell, Michigan City, RM Schahfer, and Sherburne County. These units were chosen due to the specificity of plans laid out by their owners, and is not meant to be a comprehensive reflection of all units that might be part of long term climate commitments.

projected marginal cost for the Midwest/Central region of only 75 cents in 2030, while the projected marginal cost in all other regions was zero.

This analysis is only partial and does not include a quantitative assessment of other power plants that are owned by utilities with longer-term climate commitments because they have not clearly indicated which power plants will be retired. Also, many of the utility commitments begin prior to 2030 but also include additional significant milestones for 2030, 2040 and 2050. The non-modeled CO_2 reduction commitments in this region, along with the marginal cost of 75 cents from the CPP Regional Trading and Tolling scenario, suggests that the baseline emissions will be lower than the CPP goal for this region.

2.4 Modeling Inputs and Key Areas of Uncertainty

The EPA conducts power sector analysis using IPM, a sophisticated modeling tool with detailed representation of the electric power system. This tool undergoes continual updates and enhancements to best represent the electric power system and is similar to the AEO, in that it provides baseline projections that help guide and shape regulatory efforts. As previously discussed, there have been notable fuel, technology, and other system changes that have led to revised projections of CO_2, which are incorporated into the EPA's current analysis of CPP and Final ACE and inform the EPA's choice of baseline. However, given the pace of change, key uncertainties are identified and discussed below.

2.4.1 Routine Baseline Updates and Model Considerations

The EPA routinely updates its analytics and modeling platforms in order to provide the most current framework in which to evaluate its actions. Over the past few years, there have been changes to the market economics for power plants that involve a myriad of changes that have been incorporated to best reflect the behaviors and the relative economics of power plant operators. For example:

- Routine EGU inventory updates:
    - New Electric Capacity: Inclusion of recent builds and deployment of new capacity across the country, which consists mostly of renewable energy (wind and solar) and natural gas (simple and combined cycle) due to low-cost natural gas supply

- Retirements of Existing Capacity: Retirement of existing capacity that has been removed from service due to economic and regulatory considerations (mostly aging coal capacity and some nuclear capacity)

- Electric Demand: Changes to expected electric demand levels, whereby overall growth is expected to be very small for the foreseeable future

- Fuels: Robust and cost-effective supplies of natural gas with additional pipeline capacity, particularly in the Eastern U.S.

- New or Amended State Laws or Regulations: Examples include updated climate or energy programs, energy storage mandates, new or revised RPS standards, consent decrees, and other regulatory requirements for certain power plants at the State level

- Changes to Federal Law: Examples include changes to corporate income taxes and extensions to renewable energy tax credits found in the December 2017 Tax Reform Bill

These updates and changes are reflected in the EPA's current modeling framework using IPM (see Chapter 3 of this RIA for more detail).

While the EPA makes every effort to incorporate the most up-to-date information into its modeling and analysis, such modeling may overstate emissions projections and costs of emission reductions whenever there are important and unanticipated developments in clean energy policy and technology not incorporated in previous analysis. Several examples illustrate why the pace of change in the power sector is likely to be greater than what the modeling produces:

- Legislative changes at the national and state levels. These include: 1) Changes to the 45Q tax credit to encourage more carbon capture and storage, 2) State legislative efforts in New Jersey to join RGGI, and 3) Increased renewable and clean energy mandates in states like New Mexico.[38]

- The EPA does not include in its modeling commitments made as part of IRPs that States and electric utilities develop for long-term planning, since they are not legally binding documents and can be changed and amended over time (some specific IRPs were mentioned above). However, these documents often undergo significant public review and stakeholder engagement, and utilities typically follow through with such plans unless there are unusual circumstances.

- Models do not reflect the future perfectly, and there may be greater and/or faster technology evolution and change than assumed in this modeling as many nascent

[38] New Mexico recently passed legislation that will double renewable energy use in the state by 2025, require 50% renewable energy by 2030 and 100 percent carbon free electricity generation by 2045 (New Mexico SB 489, available at https://www.nmlegis.gov).

technologies continue to develop. For example, energy storage (battery technology), advanced gas turbines, distributed energy, and end-use efficiency technologies are emerging and increasingly important areas of policymaking and investment that are likely to have impacts on the turnover of the existing fleet.

- Increased corporate commitments to procure renewable power that may go beyond State renewable standards.

- Potential changes to the cost to operate coal plants, since they have increased ramping up and down more routinely (as a group) due to market conditions, causing increased wear and tear to coal-fired units. This is important both because so many units are now being operated in a more cyclic function and because the coal-fired fleet is continuing to age. The average age of coal-steam EGUs greater than 25 MW is projected to be over 50 years old in 2030, and nearly 30 percent of these units (or almost 20 percent of total capacity) will be over 60 years old.

Other areas of uncertainty include:

- Uncertainty about the compliance pathways states would take if the CPP were eventually upheld and implemented. The EPA's analysis has primarily focused on a mass-based approach for existing sources at the state level with some additional analysis of larger trading regions.

- States also had the flexibility to use state goals that include new sources and to use rate-based trading. Full consideration of these options would likely show additional states already in compliance with the CPP.

Any of these changes would further ease the CPP compliance burden and further increase the chance that baseline emissions would be further below CPP requirements in most, if not all states, even under conservative implementation assumptions.

2.5 Additional State-level Information

This section presents several perspectives using the EPA analysis to assess the degree of effort needed to meet the CPP goals in various states. State-level data is presented showing state-level emissions, CPP goals, and the cost to meet the CPP state goals. These costs, consistent with the electric sector trends, have decreased over time for the vast majority of states.

First, emissions for each state in the baseline in 2030 are shown in Figure 2-14, along with their mass-based CPP goals. The states are ordered, from left to right, with the greatest emission-reduction shortfall on the far left and the greatest surplus in emission reduction on the far right. This approach does not incorporate any delay in CPP implementation and shows many more states already meeting their goals in the baseline in 2030 than states that are not.

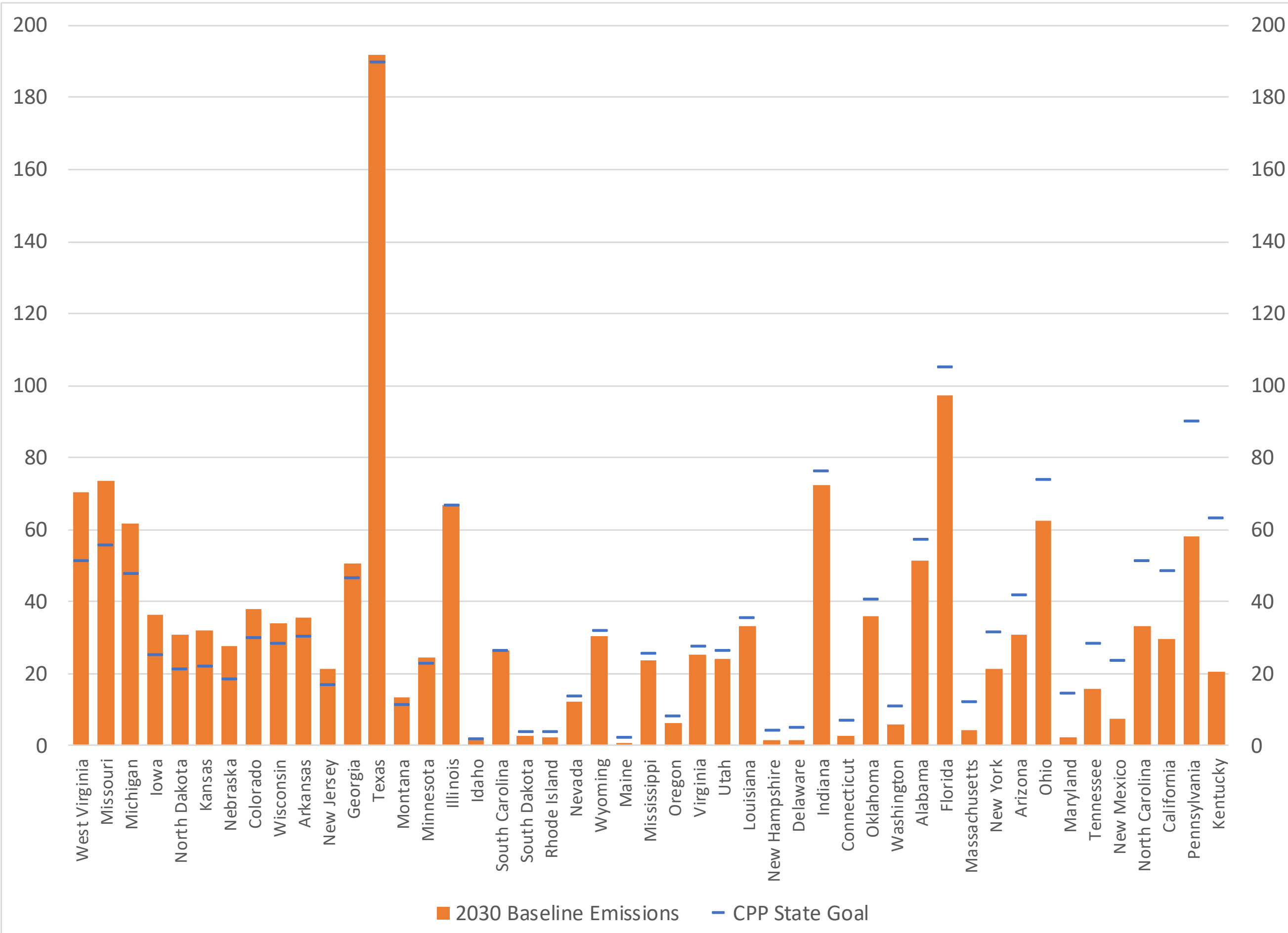

Figure 2-14 State-Level CO_2 Emissions in the EPA Baseline for 2030, Ordered by Largest Shortfall to Greatest Surplus Compared to CPP State Goals (thousand short tons)

Source: EPA, State-level goals for CPP and baseline projections of CO_2 from IPM.

The degree of shortfall shown in some states is likely overstated. As indicated earlier in this chapter, there are many states with hypothetical shortfalls that also have major investor-owned utilities that have announced clean energy targets well below what is modeled in the baseline, since the EPA does not incorporate these longer-term goals or IRPs into the modeling. These states include Missouri (Ameren), Michigan (DTE Energy and Consumers Energy), Iowa (MidAmerican Energy), Colorado, Minnesota, North Dakota, and Wisconsin (Xcel Energy).

Second, when the CPP is modeled with each state required to meet its goal, the model produces a marginal cost of compliance on a dollar per ton basis for each state. This data is shown below in Table 2-4 for various modeling iterations of CPP over the last few years, including for final ACE, using IPM. A closer look shows the marginal cost to meet the CPP state goal in 2030 has decreased over time for the vast majority of states. This is true even without implementation delay or interstate emissions trading.

In addition, the states with the highest projected marginal costs of complying with their respective state-level CPP goal are also states with electric utilities that have committed to large reductions in carbon emissions by 2030 and beyond. For example, New Jersey has committed to joining the RGGI trading program while the CPP was stayed, and was one of the states with slightly higher marginal cost under the CPP modeling. In Colorado, the state with the highest projected marginal cost of CO_2reductions, Xcel energy (the largest utility in the state) has committed to an 80% reduction in CO_2 from 2005 levels (Xcel also has generating assets in seven other states). Additionally, the Platte River Power Authority board of directors has committed to 100% renewable power by 2030 (also operating in Colorado).[39] These commitments would significantly reduce the chance that the CPP would be binding in Colorado. In Missouri, Ameren has committed to a 35% reduction in GHGs by 2030 (relative to 2005) on the way to an 80% reduction in 2050. In Michigan, the states' two largest utilities, Detroit Edison and Consumers Power, have announced ambitious carbon reduction targets.

[39] https://www.prpa.org/news/platte-river-board-passes-energy-policy/.

Table 2-4 2030 Projected Marginal Cost of Mass-Based State-Level CPP Emissions Goals, by State ($/ton CO_2)

For 2030	Final CPP RIA[40] (v5.15)	Ozone NAAQS Transport NODA[41] (v5.16)	Proposed ACE[42] (v6.17)	Final ACE (IPM 2018)
AL	$11	$0	$0	$0
AR	$10	$8	$2	$4
AZ	$20	$5	$0	$0
CA	$15	$0	$0	$0
CO	$21	$11	$11	$13
CT	$1	$7	$0	$0
DE	$0	$0	$0	$0
FL	$12	$3	$0	$0
GA	$15	$2	$1	$0
IA	$15	$6	$3	$6
ID	$24	$1	$2	$2
IL	$10	$5	$1	$0
IN	$17	$4	$0	$0
KS	$20	$10	$4	$5
KY	$2	$2	$0	$0
LA	$2	$0	$0	$0
MA	$0	$4	$0	$0
MD	$4	$0	$0	$0
ME	$2	$9	$0	$0
MI	$5	$0	$5	$5
MN	$17	$4	$2	$3
MO	$16	$10	$4	$5
MS	$10	$1	$0	$0

[40] https://19january2017snapshot.epa.gov/airmarkets/analysis-clean-power-plan_.html.
[41] https://www.epa.gov/airmarkets/epas-power-sector-modeling-support-notice-data-availability-preliminary-interstate-ozone.
[42] https://www.epa.gov/airmarkets/analysis-proposed-ace-rule.

MT	$20	$12	$8	$8
NC	$1	$0	$0	$0
ND	$12	$7	$7	$8
NE	$24	$17	$9	$10
NH	$0	$0	$0	$0
NJ	$5	$9	$7	$7
NM	$13	$0	$0	$0
NV	$14	$3	$0	$0
NY	$0	$0	$0	$0
OH	$14	$5	$0	$0
OK	$14	$0	$0	$0
OR	$0	$0	$0	$0
PA	$6	$0	$0	$0
RI	$0	$3	$0	$0
SC	$6	$0	$0	$1
SD	$14	$3	$1	$1
TN	$15	$3	$0	$0
TX	$13	$8	$0	$0
UT	$26	$10	$1	$0
VA	$4	$0	$0	$0
WA	$0	$0	$0	$0
WI	$16	$8	$2	$3
WV	$15	$5	$5	$4
WY	$18	$0	$0	$0

The modeling presented in Table 2-4 shows more than half of the states have no marginal cost, indicating that the CPP is likely to have no effect in those states. Several more states show marginal costs of less than $2/ton. Of the remaining states, several have major utilities that have announced long-term plans to support cleaner energy sources and replace existing coal plants with renewable energy. Given this information—which, again, uses the older, more conservative assumptions for CPP implementation—it is clear that there are multiple, flexible compliance pathways that states and utilities could undertake to implement the CPP either for no or virtually no cost.

2.6 Conclusion

Based on the analysis presented above, it is abundantly clear that national existing-source power sector emissions even without the CPP in effect are below the requirements set forth under the CPP, when the goals of the CPP are viewed collectively. This is also true at the regional level. Considering the national emission trends, the regional trends, the flexibility of the CPP, and the delayed time-line of the CPP, it is likely that there would be no difference between a baseline that includes the CPP and one that does not. For all these reasons, the EPA believes that repeal of the CPP under current and reasonably projected market conditions and regulatory implementation is not anticipated to have a meaningful effect on emissions of CO_2 other pollutants or regulatory compliance costs. As a result, this analysis demonstrating no significant difference in a scenario with CPP implementation and one without also satisfies any regulatory impact analysis that may be required by statute or executive order for repeal of the CPP.

2.7 Addendum: IPM Power Sector Projections

This section presents new results and projections from IPM for four scenarios:[43]

- Baseline: No regulatory requirements for existing EGUs under 111(d).
- CPP with National Trading and Tolling: This includes delaying implementation of CPP by three years and allowing nearly unlimited trading across all states.[44]
- CPP with Regional Trading and Tolling: This includes delaying implementation of CPP by three years and allowing trading within six geographic regions shown in Figure 2-12.

[43] All of these CPP scenarios capture the ability for EGUs to bank allowances. The detailed IPM results for these scenarios can be found in the ACE docket and on EPA's IPM website at: https://www.epa.gov/airmarkets/clean-air-markets-power-sector-modeling

[44] For purposes of this scenario, California and the Regional Greenhouse Gas Initiative (RGGI) states are excluded from trading with other states for CPP, and must meet their respective legally binding state/regional commitments in addition to the CPP goals (for RGGI, the CPP goals are aggregated and trading is allowed amongst RGGI states). The CPP requirements are non-binding for California and RGGI because the state commitments are more stringent.

- CPP with Limited Trading: This follows the same assumed CPP implementation as presented in the Final CPP and proposed ACE RIAs, where each state had to meet its goal individually and implementation begins in 2022.

The modeling results and projections show that the CPP, accounting for trading and tolling, produces the same outcomes as the baseline scenario. That is, the CPP has no impact under this form of CPP implementation. Below are key results of the IPM scenarios, including CO_2 emissions, systemwide costs, and generation mix.

Note that the modeling for both CPP scenarios reflects an option to improve heat rates between about 2% and 4% at a cost of $110/kW, based on assumptions made in conjunction with the finalization of the CPP in 2015. This option is not available in the baseline modeling. In the CPP with Trading and Tolling scenario, the model projects the deployment of a small amount of HRI-retrofitted capacity (about 150 MW) based on market fundamentals. This small deployment of HRI affects the cost and emissions projections in the modeling, as reflected in the small differences presented below. These differences in projections do not result from the CPP-based CO_2 emissions constraints, for which the model projects a $0 allowance price.

Table 2-5 Emissions Projections

	Baseline	CPP (National Trading and Tolling)	Percent Change from Baseline	CPP (Limited Trading)	Percent Change from Baseline	CPP (Regional Trading and Tolling)	Percent Change from Baseline
CO_2 (million short tons)							
2025	1,774	1,774	0.0%	1,733	-2.3%	1,767	-0.4%
2030	1,743	1,743	0.0%	1,681	-3.5%	1,733	-0.6%
2035	1,719	1,719	0.0%	1,667	-3.0%	1,709	-0.6%
SO_2 (thousand tons)							
2025	912.6	913.2	0.1%	894.8	-1.9%	902.4	-1.1%
2030	885.6	887.2	0.2%	853.6	-3.6%	878.7	-0.8%
2035	817.0	815.6	-0.2%	769.7	-5.8%	807.5	-1.2%
NOx (thousand tons)							
2025	844.4	844.4	0.0%	803.1	-4.9%	838.1	-0.7%
2030	810.1	810.1	0.0%	761.6	-6.0%	803.7	-0.8%
2035	752.8	753.2	0.0%	712.6	-5.3%	747.1	-0.8%
Hg (tons)							
2025	4.7	4.7	0.0%	4.5	-3.4%	4.7	-0.6%
2030	4.5	4.5	0.0%	4.3	-4.5%	4.4	-0.7%
2035	4.0	4.0	0.0%	3.9	-3.4%	4.0	-1.0%

Note: million short tons, thousand short tons, and short tons for CO_2, SO_2/NO_X, and Hg respectively.

Table 2-6 Annual Compliance Costs (Millions 2016$)

	2025	2030	2035
CPP (National Trading and Tolling)	$1.8	$0.2	$5.1
CPP (Limited Trading)	$689.6	$929.0	$517.8
CPP (Regional Trading and Tolling)	-$32.0	$27.2	$138.6

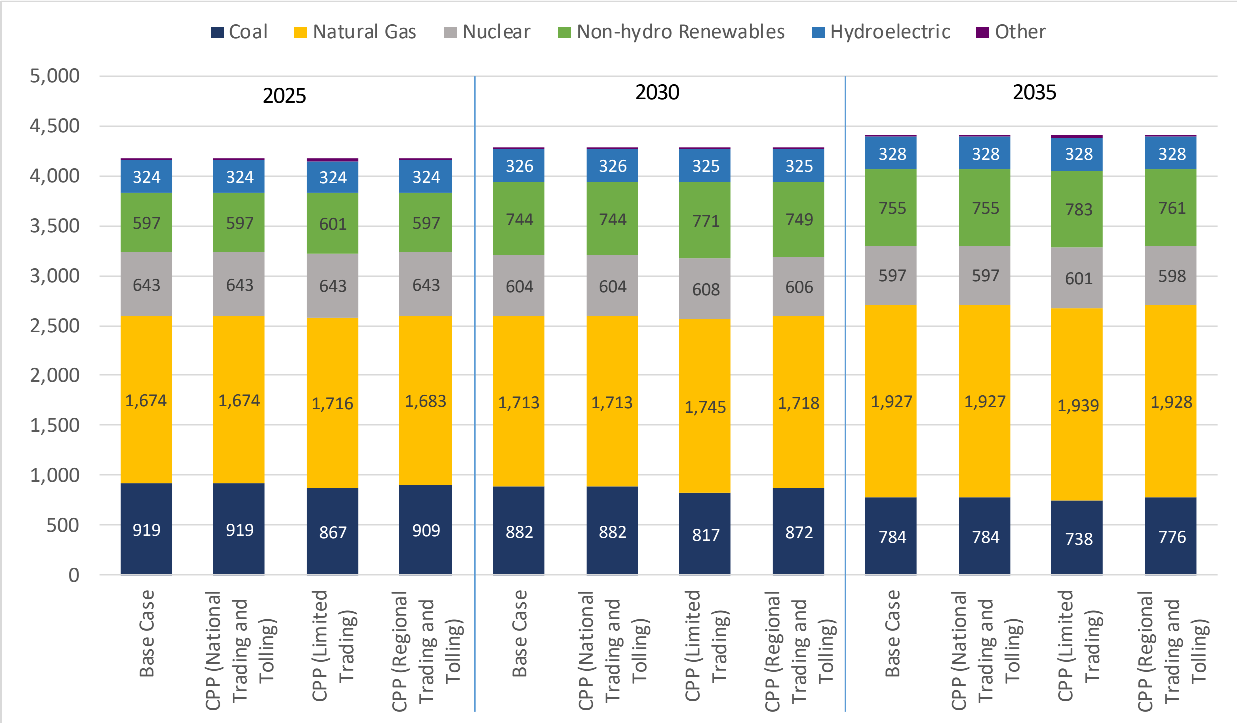

Figure 2-15 Generation Mix (GWh)
Source: IPM

Table 2-7 Installed Generating Capacity (GW)

	Baseline	CPP (National Trading and Tolling	Percent Change from Baseline	CPP (Limited Trading)	Percent Change from Baseline	CPP (Regional Trading and Tolling)	Percent Change from Baseline
2025							
Coal	172	172	0%	167	-3%	171	-1%
NG Combined Cycle (existing)	262	262	0%	262	0%	262	0%
NG Combined Cycle (new)	3	3	0%	5	79%	3	21%
Combustion Turbine	151	151	0%	151	0%	151	0%
Oil/Gas Steam	72	72	0%	72	0%	72	0%
Non-Hydro Renewables	210	210	0%	213	1%	211	0%
Hydro	110	110	0%	110	0%	110	0%
Nuclear	81	81	0%	81	0%	81	0%
Other	12	12	0%	12	0%	12	0%
Total	1,073	1,073	0%	1,073	0%	1073	0%
2030							
Coal	170	170	0%	165	-3%	168	-1%
NG Combined Cycle (existing)	262	262	0%	262	0%	262	0%
NG Combined Cycle (new)	12.7	12.7	0%	15	22%	13	5%
Combustion Turbine	152	152	0%	151	0%	152	0%
Oil/Gas Steam	72	72	0%	71	0%	72	0%
Non-Hydro Renewables	266	266	0%	272	3%	267	1%
Hydro	111	111	0%	110	0%	110	0%
Nuclear	77	77	0%	77	1%	77	0%
Other	13	13	0%	13	0%	13	0%
Total	1,133	1,133	0%	1,138	0%	1134	0%
2035							
Coal	165	165	0%	162	-2%	165	0%
NG Combined Cycle (existing)	262	262	0%	262	0%	262	0%
NG Combined Cycle (new)	38	38	0%	42	9%	39	2%
Combustion Turbine	164	164	0%	161	-2%	163	-1%
Oil/Gas Steam	72	72	0%	71	0%	72	0%
Non-Hydro Renewables	270	270	0%	277	3%	272	1%
Hydro	111	111	0%	111	0%	111	0%
Nuclear	75	75	0%	76	1%	76	0%
Other	13	13	0%	13	0%	13	0%
Total	1,170	1,170	0%	1,175	0%	1171	0%

CHAPTER 3: COST, EMISSIONS, ECONOMIC, AND ENERGY IMPACTS

3.1 Introduction

This chapter presents the compliance cost, emissions, economic, and energy impact analysis for the power sector, in support of this final rulemaking. The results are generated from a detailed power sector model called the Integrated Planning Model (IPM),[1] a version of which is developed and used by the EPA to support regulatory efforts. The model can be used to examine air pollution control policies for a variety of pollutants throughout the contiguous United States for the entire power system.

3.2 Overview

This analysis is intended to be an illustrative representation and analysis of the final ACE rule.[2] The final rule presents a framework for states to develop state plans that will establish standards of performance for existing affected sources of GHG emissions. The final rule does not itself specify any standard of performance, but rather establishes the "best system of emission reduction"[3] (BSER), i.e. technology options for heat rate improvements (HRI), that states consider as they develop standards of performance and state plans. States are able to consider remaining useful life and other source-specific factors in applying the BSER and determining a standard of performance. In turn, the specific technologies that a source might use to comply with its standard of performance is generally within the discretion of the source. In addition, the baseline for this analysis, as shown in Chapter 2, and is called the "baseline".

For these reasons, there is considerable uncertainty regarding the specific standards of performance states will apply to their sources and the technology measures that might be implemented as a result of that process. Hence, this analysis presents an illustrative policy scenario that is intended to broadly reflect how states might apply BSER and develop state plans and is intended to inform and present the potential impacts of the final rule. The illustrative policy scenario is described in detail in Chapter 1. This illustrative policy scenario assigns the same group-specific percentage HRI and associated average capital cost to each unit within each

[1] The specific version model used in this RIA is operated by ICF International, at EPA's direction.
[2] For more details on legal authority and justification of this action, see rule preamble.
[3] The best system of emission reduction (BSER) is outlined in the CAA 111(d), see preamble for further discussion.

of 12 groups of affected coal steam unit in the contiguous U.S. The coal-fired EGUs are grouped based on generating capacity and reported heat rate (see below). The analysis *is not* meant to reflect what the EPA believes can be undertaken at each affected source, but rather to estimate potential national impacts by applying control measures that the EPA believes are reasonable, on an average basis. Given the unique nature of each individual generating unit and the lack of data and information on specific individual unit-level actions with regards to the BSER technologies, in addition to uncertainty about the standards of performance states will apply to their sources, the EPA believes that this illustrative modeling approach is suitable to inform the potential impacts of the rule from a national perspective.

As with any detailed modeling and analysis that attempts to quantify the potential future impact of a regulatory requirement on an industry, there are key areas of uncertainty. Some uncertainties pertain to how states choose to implement to rule, while there are also are uncertainties for how affected sources will implement and respond to the regulatory requirements. There are also broader uncertainties about the overall operation of the electric system. These factors are discussed later in this chapter and help provide context to the overall rule, and its potential impacts. Although there are areas of uncertainty, the EPA believes that this analysis reflects the best available information at the time of analysis, and is a meaningful, credible, and appropriate reflection of the potential impacts of the rule using the best available tools.

3.3 Power Sector Modeling Framework

IPM is a state-of-the-art, peer-reviewed, dynamic linear programming model that can be used to project power sector behavior and examine prospective air pollution control policies throughout the contiguous United States for the entire electric power system. It provides forecasts of least cost capacity expansion, electricity dispatch, and emission control strategies while meeting energy demand and environmental, transmission, dispatch, and reliability constraints. The EPA has used IPM for over two decades to better understand power sector behavior into the future and to evaluate the economic and emission impacts of prospective environmental policies. 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 summarized here as well as all other model assumptions and inputs.[4] The model also incorporates a detailed representation of the fossil-fuel supply system that is used to forecast equilibrium fuel prices for natural gas and coal. The model accounts for all significant existing federal and state air, water and land use regulations.

The costs presented in this RIA reflect the IPM-projected annualized estimates of private compliance costs. The IPM-projected annualized estimates of private compliance costs provided in this analysis are meant to show the change in production (generating) costs to the power sector in response to various regulatory changes. The private compliance costs equal the difference between capital, operating, and fuel expenditures net of taxes and subsidies in the electricity sector between a baseline and policy scenario. This RIA does not identify who ultimately bears these compliance costs, such as owners of generating assets through changes in their profits or electricity consumers through changes in their bills, although the potential impacts on consumers and producers are described in Chapter 5.[5] Furthermore, the EPA uses the projection of private compliance costs as an estimate of the social cost of the final requirements, as the social cost is the appropriate metric for formal economic welfare analysis.[6] Section 3.9 describes the limitations with using this estimate of private compliance costs as an estimate of the social cost.

To estimate these annualized capital costs, 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 cost of capital (private discount rate), the amount of insurance coverage required, local property taxes, and the life of capital. It is important to note that there is no single CRF factor applied in the model; rather, the CRF varies across technologies in the model to better simulate power sector decision-making.

While the CRF is used to annualize costs within IPM, a discount rate is used to estimate the net present value of the intertemporal flow of the annualized capital and operating costs. The optimization model then identifies power sector investment decisions that minimize the net

[4] For documentation, see https://www.epa.gov/airmarkets/clean-air-markets-power-sector-modeling
[5] As discussed in further detail in Chapter 5, the ultimate incidence of this final action will depend on the distribution of both the costs and the health and welfare impacts presented in Chapter 4 across households.
[6] See, Tietenberg and Lewis, 2008; Freeman, 2003, and USEPA, 2010.

present value of all private costs over the full planning horizon while satisfying a wide range of demand, capacity, reliability, emissions, and other constraints. As explained in model documentation, the discount rate is derived as a weighted average cost of capital that is a function of capital structure, post-tax cost of debt, and post-tax cost of equity. It is important to note that this discount rate is selected for the purposes of best simulating power sector behavior, and not for the purposes of discounting social costs or benefits.

The EPA has used IPM extensively over the past two decades to analyze options for reducing power sector emissions. Previously, the model has been used to forecast the costs, emission changes, and power sector impacts for the Clean Air Interstate Rule (CAIR), Cross-State Air Pollution Rule (CSAPR), the Mercury and Air Toxics Standards (MATS), and the Clean Power Plan (CPP). IPM has also been used to estimate the air pollution reductions and power sector impacts of water and waste regulations affecting EGUs, including Cooling Water Intakes (316(b)) Rule, Disposal of Coal Combustion Residuals from Electric Utilities (CCR) and Steam Electric Effluent Limitation Guidelines (ELG).

The model and the EPA's input assumptions undergo periodic formal peer review. The rulemaking process also provides opportunity for expert review and comment by a variety of stakeholders, including owners and operators of capacity in the electricity sector that is represented by the model, public interest groups, and other developers of U.S. electricity sector models. The feedback that the Agency receives provides a highly-detailed review of key input assumptions, model representation, and modeling results.

3.4 Recent Updates to the EPA's Power Sector Modeling Platform v6 using IPM

In early 2019 the EPA updated its application of IPM to the IPM v6 November 2018 Reference Case. The Reference Case for this analysis is a business-as-usual scenario that would be expected under market and regulatory conditions in the electricity and related sectors in the absence of this rule. As such, the IPM Reference Case represents the power sector component of the baseline for this RIA. This latest application incorporates routine data updates and reflects a robust representation of electricity generation and related fuel markets. Important updates to the model since the ACE proposal RIA include:

- Use of the Energy Information Agency's (EIA) Annual Energy Outlook (AEO) 2018 demand projections
- Updated inventory of State and Federal power sector regulations
- Updates to the EPA's National Electric Energy Data System, the database of existing and planned-committed units and their emission control configurations
- Adjustments and updates to nuclear operating costs, based on information from EIA
- Updated assumptions regarding NO_X emissions rates for small fossil units
- Incorporated the implications of the December 2017 Tax Reform Bill in the discount rate and capital charge rate calculations

More information on these updates is available in the comprehensive model documentation, which is available on the EPA's website.[7]

This analysis reflects the best data available to the EPA at the time the modeling was conducted. As with any modeling of future projections, many of the inputs are uncertain. In this context, notable uncertainties include the cost of fuels, the cost to operate existing power plants, the cost to finance, construct, and operate new power plants, infrastructure, demand, and policies affecting the electric power sector. The modeling conducted for this RIA is based on estimates of these variables, which were derived from the data currently available to the EPA. However, future realizations of these characteristics may deviate from expectations. The results of counterfactual simulations presented in this RIA are not a prediction of what will happen, but rather projections of plausible scenarios describing how this final regulatory action may affect electricity sector outcomes in the absence of unexpected shocks. The results of this RIA should be viewed in that context.

3.5 Scenario Analyzed

An illustrative policy scenario was analyzed to estimate potential costs and benefits of the final rules. In this illustrative policy scenario, we assume that HRI potential and costs will differ based on unit size and efficiency, and not other sources of heterogeneity including location of units. Affected sources were divided into twelve groups based on three size categories and four efficiency categories. A representative cost and performance assumption for HRI from the

[7] See Documentation for the EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model, available at: https://www.epa.gov/airmarkets/epas-power-sector-modeling-platform-v6-using-ipm

candidate technologies was identified for each grouping. The assumed HRI cost and performance differs across the groups. The group-specific cost and performance assumptions were then applied to each unit in the group in the illustrative analysis. We then modeled the application of these assumptions in the power sector which provides a basis for the costs, emissions, and benefits analyses that illustrate the potential impacts of the final rules. More information on the development of the illustrative policy scenario assumptions can be found in Chapter 1.

Table 3-1 HRI Cost and Performance Assumptions for Illustrative Policy Scenario, by Unit Capacity and Heat Rate

	Small (<25 MW to 200 MW)	**Medium** (200 MW to 500 MW)	**Large** (>500 MW)
Group 1 **(Most Efficient)** ≤ 9,773 Btu/kWh	N/A (<1%)	N/A (1%)	N/A (10%)
Group 2 9,774 –10,396 Btu/kWh	1.0% at $47/kW (1%)	0.8% at $32/kW (7%)	0.8% at $25/kW (36%)
Group 3 10,397 – 11,019 Btu/kWh	2.1% at $47/kW (4%)	1.9% at $32/kW (13%)	1.8% at $25/kW (15%)
Group 4 **(Least Efficient)** ≥ 11,020 Btu/kWh	3.2% at $47/kW (4%)	2.9% at $32/kW (7%)	2.8% at $25/kW (3%)

Note: Share of total capacity represented by each category in parentheses.

The year of implementation for the illustrative policy scenario is 2025, as an approximation for when the standards for performance under the final rule might be implemented. The requirements do not change over time.

As discussed above, the final rule requires states to develop standards of performance based on EPA's determination of BSER, which are methods of HRI that reduce CO_2 emissions. The standards of performance are not represented in the model directly and, as discussed above, are uncertain because the applicability of these technologies across the fleet and the standards of performance the states will require are uncertain.[8] In practice, affected sources may have certain flexibilities in how they comply with the standards of performance that differs from the

[8] Note that, in the modeling, the total cost of the HRI is reflected as a capital cost. However, for some HRI technologies, a small share of the total cost may be variable, and thus the cost of the HRI might have a small effect on dispatch decisions.

technologies used to determine the sources' standards of performance, but this possibility is not captured in the modeling for this RIA.

In addition, the implementation of HRI at units to meet a standard of performance under ACE is considerably different than "building block 1" under CPP. Under CPP, the building blocks represented different groups of technologies (blocks) that were used to establish state-level CO_2 emission goals. Sources were required to meet the state-level emissions goals of the rule, but were not required to adopt any particular building block as a requirement of the rule. As such, the modeling for CPP did not require HRI, although it was included as one of many compliance options in the modeling. The modeling of CPP, as shown in Chapter 2, also shows that the CPP goals are not expected to produce reductions beyond the baseline in most scenarios, and thus CPP has no costs or benefits. In the illustrative policy scenario for ACE, the HRI is implemented as unit-level requirement, and thus has costs and benefits relative to the baseline (regardless of whether the CPP is included in the baseline). It is not appropriate to think of ACE as the same as building block 1 under CPP, since there are important differences.

For ease of modeling, in the scenario representing the final ACE rule, sources may adopt the assumed HRI level or may retire in the model, based on prevailing economics. However, it is possible that states may use opportunities afforded to them in the final rule when applying BSER to avoid retirement of affected sources, and the scenario does not capture this possibility. However, as discussed in Section 3.7.5, the modeling of the illustrative policy scenario projects about 2 GW of coal retirements, which is a small share of total coal capacity.

It is important to note that current data limits our ability to apply more customized HRI and cost functions to specific units. Due to these limitations, the EPA used the best available information, research, and analysis to arrive at the assumptions used in this scenario.

3.6 Monitoring, Reporting, and Recordkeeping Costs

The EPA projected monitoring, reporting and recordkeeping (MR&R) costs for both state entities and affected EGUs for the years 2023, 2025, 2030, and 2035. The MR&R cost estimates presented below apply to the illustrative policy scenario.

In calculating the costs for states, the EPA estimated personnel costs to oversee compliance, and review and report annually to the EPA on program progress relative to meeting the state's reduction goal. To calculate the national costs, the EPA estimated that 43 states and 277 facilities would be affected. The EPA estimated that the majority of the additional monitoring cost to EGUs would be in calculating net energy output. Since the majority of EGUs have some energy usage meters or other equipment available to them, EPA believes a new system for calculating net energy output is not needed.

The EPA has made it a priority to streamline reporting and monitoring requirements. In this rule, the EPA is making implementation as efficient as possible for both the states and the affected EGUs by allowing state plans to use the current monitoring and recordkeeping requirements and pathways that have already been well established in other EPA rulemakings. For example, under the Acid Rain Program's continuous emissions monitoring, 40 CFR Part 75, The EPA has established requirements for the majority of the EGUs that would be affected by a 111(d) state plan to monitor CO_2 emissions and report that data using the Emissions Collection and Monitoring Plan System (ECMPS). Additionally, since the CO_2 hourly data is already reported to the EPA's ECMPS there is no additional burden associated with the reporting of that data. Since the ECMPS pathway is already in place, the EPA will allow for states to use the ECMPS system to facilitate the data reporting of the additional energy output data required under the emission guidelines.

While not a requirement, if states choose the form of standard to be reflective of net energy output there may be additional burden for an affected EGU. The EPA estimates that it would take three working months for a technician to retrofit any existing energy meters to reflect net energy output. Additionally, the EPA believes that 40 hours will be needed for each EGU operator to read the rule and understand how the facility will comply with the rule, based on an average reading rate of 100 words per minute and a projected rule word count of 300,000 words.[9] Also, after all modifications are made at a facility to measure net energy output, each EGU's

[9] According to one source, the average person can proofread at about 200 words per minute on paper and 180 words per minute on a monitor. (Source: Ziefle, M. 1988. "Effects of Display Resolution on Visual Performance." Human Factors 40(4):554-68). Due to the highly technical nature of the rule requirements in subpart UUUUa, a more conservative estimate of 100 words per minute was used to determine the burden estimate for reading and understanding rule requirements.

Data Acquisition System (DAS) would need to be upgraded to supply the rate-based emissions value to either the state or the EPA's Emissions Collection and Monitoring Plan System (ECMPS). Note the costs to develop net energy output monitoring and to upgrade each facility's DAS system are one-time costs incurred in 2023. Recordkeeping and reporting costs substantially decrease after 2023. The projected costs for 2023, 2025, 2030, and 2035 are summarized below.

In calculating the cost for states to comply, the EPA estimates that each state will rely on the equivalent of two full time staff to oversee program implementation, assess progress, develop possible contingency measures, perform state plan revisions and host the subsequent public meetings if revisions are indeed needed, download data from the ECMPS for their annual reporting and develop their annual EPA report. The burden estimate was based on an analysis of similar tasks performed under the Regional Haze Program, whereby states were required to develop their list of eligible sources, draft implementation plans, revise initial drafts, identify baseline controls, identify data gaps, identify initial strategies, conduct various reviews, and manage their programs. A total estimate of 78,000 hours of labor performed by seven states over a three-year period resulted in 3,714 hours per year, per entity. Due to the nature of this final rule whereby we believe each state's air office and the energy office will both be involved in performing the above-mentioned tasks, we rounded up to the equivalent of two full time staff, which totaled 4,160 hours per year.[10] Table 3-2 presents the estimates of the annual state and industry respondent burden and costs of reporting and recordkeeping for the illustrative policy scenario in 2023, 2025, 2030, and 2035.

[10] Renewal of the ICR for the Regional Haze Rule, Section 6(a) Tables 1 through 4 based on 7 states' burden. EPA-HQ-OAR-2003-0162-0001.

Table 3-2 Years 2023, 2025, 2030, and 2035: Summary of State and Industry Annual Respondent Burden and Cost of Reporting and Recordkeeping Requirements (million 2016$)

Totals	Total Annual Labor Burden (Hours)	Total Annual Labor Costs	Total Annualized Capital Costs	Total Annual O&M Costs	Total Annualized Costs	Total Annual Respondent Costs
States						
2023	180,000	14	0	0.031	0.031	14
2025	190,000	15	0	0.021	0.021	15
2030	190,000	15	0	0.021	0.021	15
2035	190,000	15	0	0.021	0.021	15
Industry						
2023	150,000	14	0	0.28	0.28	14
2025	0	0	0	0	0	0
2030	0	0	0	0	0	0
2035	0	0	0	0	0	0
Total						
2023	330,000	28	0	0.31	0.31	28
2025	190,000	15	0	0.021	0.021	15
2030	190,000	15	0	0.021	0.021	15
2035	190,000	15	0	0.021	0.021	15

Note: All estimates are rounded to two significant figures, so figures may not sum due to independent rounding.

The labor costs associated with MR&R activities represent part of the total costs of the rule. Other categories of labor that may be impacted by the rule are described in Section 5.2 "Employment Impacts". Estimates in Table 3-2 of the total annual labor burden in hours, for MR&R activities, can be converted to estimates of full-time equivalent (FTE) jobs using the above estimate of 4,160 hours per year for two full time staff, i.e. 2,080 hours per year for one FTE job. Within this category of MR&R labor, we estimate approximately 73 FTE for industry in illustrative policy scenario year 2023, and no impact in years 2025, 2030, and 2035.

As shown in Table 3-2, almost all MR&R costs are labor costs. In the context of other categories of labor potentially impacted by the rule, such as labor associated with HRI, labor needed for production of electricity by type of fuel, or labor needed for coal or natural gas fuel production, which are all described in Section 5.2 "Employment Impacts", MR&R labor is a smaller category. See Section 5.2 for a discussion of the current U.S. economic climate with low unemployment and full employment conditions, which indicates that while affected workers may experience potential impacts due to the rule, overall, such impacts would most likely be temporary and aggregate employment would be unchanged.

3.7 Projected Power Sector Impacts

The following sections report the results from the power sector modeling, comparing the illustrative policy scenario to the baseline as the primary comparison point of reference.[11] Note that, unlike the RIA for the proposed rule, the baseline does not include the CPP.

3.7.1 Projected Emissions

Relative to the baseline, the EPA projects that the illustrative policy scenario results in an annual CO_2 emissions decrease from the electricity sector in the contiguous U.S. of less than one percent in 2025, 2030, and 2035, as shown in Table 3-3. The EPA projects that both baseline and illustrative policy case system-wide CO_2 emissions are 36% lower than 2005 emissions levels by 2035, as shown in Table 3-4 (inclusion of 2005 emissions provides a static comparison point and is consistent with past RIAs).

Table 3-3 Projected CO_2 Electric Sector Emission Impacts, Relative to Baseline

	CO_2 Emissions (MM Short Tons)			CO_2 Emissions Change (MM Short Tons)			CO_2 Emissions Change Percent Change		
	2025	2030	2035	2025	2030	2035	2025	2030	2035
Baseline	1,774	1,743	1,719						
Illustrative Policy Scenario	1,762	1,732	1,709	-12	-11	-9.3	-0.7%	-0.7%	-0.5%

Table 3-4 Projected Electric Sector CO_2 Emission Impacts, Relative to 2005

	CO_2 Emissions (MM Short Tons)			CO_2 Emissions: Change from 2005 (MM Short Tons)			CO_2 Emissions: Percent Change from 2005		
	2025	2030	2035	2025	2030	2035	2025	2030	2035
Baseline	1,774	1,743	1,719	-909	-940	-964	-34%	-35%	-36%
Illustrative Policy Scenario	1,762	1,732	1,709	-921	-951	-974	-34%	-35%	-36%

[11] The detailed modeling output files for all of the scenarios described in this chapter are available in the docket and on the EPA's website, which include additional data and information, including results from additional model run years.

Table 3-5 shows that under the illustrative policy scenario, the EPA projects a less than one percent decrease in sulfur dioxide (SO_2) emissions annually in 2025, 2030, and 2035. Additionally, the EPA projects a less than one percent decrease in nitrogen oxides (NO_X) emissions annually in 2025, 2030, and 2035. In addition to decreases in SO_2 and NO_X emissions, the EPA also projects a less than one percent decrease in mercury (Hg) emissions in 2025, 2030, and 2035.

Table 3-5 Projected Electric Sector Emissions of SO_2, NO_X, and Hg

	Baseline	Illustrative Policy Scenario	Emissions Change	Percent Change from Base
SO_2 (thousand tons)				
2025	912.6	908.5	-4.1	-0.4%
2030	885.6	879.9	-5.7	-0.6%
2035	817.0	810.6	-6.4	-0.8%
NO_X (thousand tons)				
2025	844.4	837.1	-7.3	-0.9%
2030	810.1	803.0	-7.1	-0.9%
2035	752.8	746.8	-6.0	-0.8%
Hg (tons)				
2025	4.7	4.7	-0.03	-0.7%
2030	4.5	4.4	-0.03	-0.7%
2035	4.0	4.0	-0.03	-0.6%

3.7.2 Projected Compliance Costs

The power industry's compliance costs are represented in this analysis as the change in total electric power generation costs, also known as the system costs, between the baseline and the illustrative policy scenario, including the cost of MR&R. The system costs include projected power industry expenditures on capital, operating and fuels, and reflect the least cost power system outcome in response to assumed market and regulatory requirements. In simple terms, the compliance costs are an estimate of the change in projected system costs between two scenarios. This RIA does not identify who ultimately bears these compliance costs, such as owners of generating assets through changes in their profits or electricity consumers through changes in their bills, although the potential impacts on consumers and producers are described in Chapter 5.[12]

As shown in Table 3-6, the EPA projects that the annual compliance costs of the illustrative policy scenario range from about $290 million in 2025 to $25 million in 2035. The lower 2035 compliance cost estimate results from a temporal shift in projected new generation capacity and projected changes in fuel prices over time and between scenarios.[13]

Table 3-6 Annualized Compliance Costs, Relative to Baseline (millions of 2016$)

	2025	2030	2035
Illustrative Policy Scenario	$290	$280	$25

Note: Includes MR&R costs (see Section 3.6). All estimates are rounded to two significant figures.

The annual compliance cost of the illustrative policy scenario is the difference in total annualized production costs between the baseline and the illustrative policy scenario, plus the costs of monitoring, reporting, and recordkeeping. The breakdown of the costs that compose the production costs are also shown below. The total production costs can be broken down into operations and maintenance costs (both variable and fixed), fuel expenditures, and capital expenditures. The changes in projected costs are related to the HRI assumed that most affected sources are assumed to install in the illustrative policy scenario. For example, the HRI assumes some modest increase in capital cost investment, while improving overall performance and heat rate of affected sources (which leads to slightly less fuel expenditures).[14]

[12] Note that the projected compliance costs in this RIA reflect changes in total system costs and do not reflect potential projected changes in electricity consumer expenditures (e.g., expenditures on net imports, which are a very small percentage of total system costs).

[13] Changes in the cost of generation in the power sector arise because of the cost of investing in HRI, changes in fuel consumption at affected sources, and changes in costs from other non-regulated sources. The HRI assumed to be adopted in the illustrative policy scenario are energy (fuel) efficiency investments. For the purposes of this analysis, the fuel savings for affected sources associated with these energy efficiency investments are treated as an offsetting cost, and not a benefit, of this regulatory action.

[14] Note that the projected total system fuel costs decrease includes overall net decreases for some fuels (e.g., coal) and increases for other fuels (e.g., nuclear).

Table 3-7 Total Production Costs (millions of 2016$)

	2025	2030	2035
Variable O&M			
Baseline	10,057	9,963	9,931
Illustrative Policy Scenario	10,052	9,978	9,948
Change	-5	15	18
Fixed O&M			
Baseline	50,211	51,383	52,644
Illustrative Policy Scenario	50,126	51,312	52,590
Change	-85	-70	-53
Fuel			
Baseline	67,405	67,943	69,948
Illustrative Policy Scenario	67,075	67,616	69,464
Change	-329	-326	-484
Capital			
Baseline	14,077	23,085	27,420
Illustrative Policy Scenario	14,770	23,727	27,949
Change	693	643	529
Total Production Costs			
Baseline	141,750	152,374	159,942
Illustrative Policy Scenario	142,024	152,634	159,951
Change	274	260	10

Note: Does not include MR&R costs (see Section 3.6).

3.7.3 Projected Compliance Actions for Emissions Reductions

As discussed above, the illustrative policy scenario requires that most affected sources invest in measures that improve the heat rate performance of each source to continue operation, or they must otherwise retire. A relatively small number of affected sources (see below) are projected to retire while all others are assumed to adopt the HRI, which reduces the amount of fuel necessary to generate electricity, and thus decreases the CO_2 emissions rate (per unit output) of affected sources. The generation-weighted average CO_2 emissions rate from coal-fired EGUs larger than 25 MW is 1.2 percent lower in the illustrative policy scenario than the baseline in the years 2025, 2030, and 2035. In the modeling of the illustrative policy scenario, the sources that are projected to operate are projected to, on average, increase generation as a result of the HRI. This increase in generation, coupled with a decrease in the CO_2 emissions rate, largely results in an overall decrease in CO_2 emissions from the affected sources, relative to the baseline. Under the illustrative policy scenario, emissions are projected to increase at some EGUs, representing a small share of overall capacity. See Table 3-8 below for a summary of projected CO_2 emissions by generation sources under each scenario, and Table 3-9, Table 3-10, and Table 3-11 for a summary of projected SO_2, NO_X, and Hg emissions, respectively. Emission changes are reported for all coal-fired EGUs, which are those subject to the final rule, and all other emitting electricity generators. See Figure 3-1, Figure 3-2, Figure 3-3, Figure 3-4, and Figure 3-5 for a summary of the distribution of projected CO_2, SO_2, and NO_X emissions increases and decreases at affected units in 2025 in the illustrative policy scenario. These figures present the total capacity and total 2025 emissions changes in the illustrative policy scenario relative to the baseline, aggregated into two groups: units projected to increase emissions, and units projected to decrease emissions. These aggregate projected changes are further broken down by the four heat rate groups on which the assumed HRI are assigned in the modeling (see Table 3-1). It is important to again note the illustrative nature of the policy scenario when interpreting these results. For further discussion, see Limitations section below.

Table 3-8 Projected CO_2 Emissions by Generation Source (MM short tons)

	Coal > 25 MW	All Other	Total
2025			
Baseline	1,004	770	1,774
Illustrative Policy Scenario	995	767	1,762
Change	-10	-3	-12
2030			
Baseline	964	778	1,743
Illustrative Policy Scenario	955	776	1,732
Change	-9	-2	-11
2035			
Baseline	859	860	1,719
Illustrative Policy Scenario	850	860	1,709
Change	-9	0	-9

Table 3-9 Projected SO_2 Emissions by Generation Source (thousand short tons)

	Coal > 25 MW	All Other	Total
2025			
Baseline	877	35	913
Illustrative Policy Scenario	873	35	908
Change	-4	0	-4
2030			
Baseline	859	27	886
Illustrative Policy Scenario	853	27	880
Change	-6	1	-6
2035			
Baseline	798	19	817
Illustrative Policy Scenario	791	20	811
Change	-8	1	-6

Table 3-10 Projected NO_X Emissions by Generation Source (thousand short tons)

	Coal > 25 MW	All Other	Total
2025			
Baseline	608	237	844
Illustrative Policy Scenario	603	235	837
Change	-5	-2	-7
2030			
Baseline	578	232	810
Illustrative Policy Scenario	572	231	803
Change	-6	-1	-7
2035			
Baseline	511	242	753
Illustrative Policy Scenario	504	242	747
Change	-6	0	-6

Table 3-11 Projected Hg Emissions by Generation Source (short tons)

	Coal > 25 MW	All Other	Total
2025			
Baseline	3.3	1.4	4.7
Illustrative Policy Scenario	3.3	1.4	4.7
Change	0.0	0.0	0.0
2030			
Baseline	3.1	1.4	4.5
Illustrative Policy Scenario	3.1	1.4	4.4
Change	0.0	0.0	0.0
2035			
Baseline	2.7	1.3	4.0
Illustrative Policy Scenario	2.7	1.3	4.0
Change	0.0	0.0	0.0

Note: Values may not sum due to rounding.

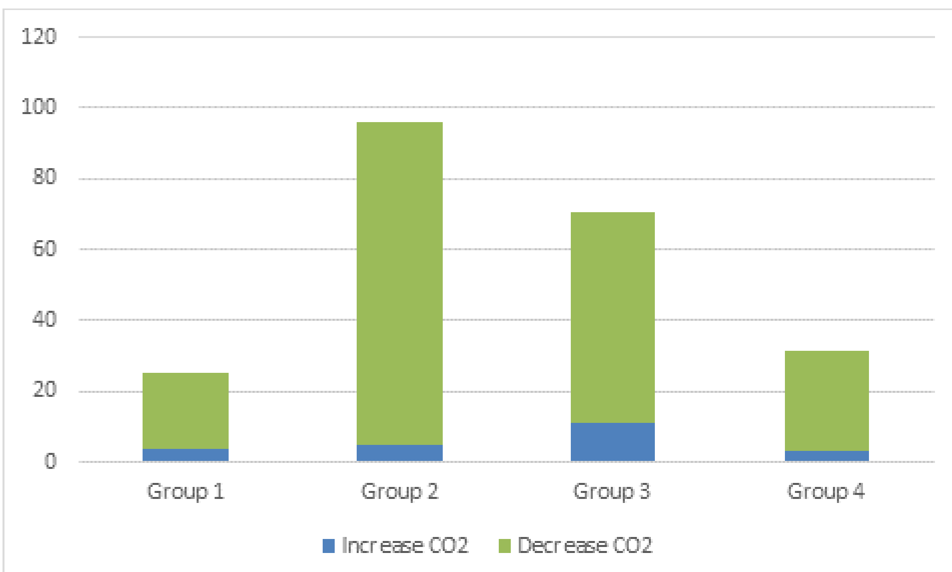

Figure 3-1 Projected Distribution of Affected Unit Capacity in 2025, by Heat Rate Group (GW)

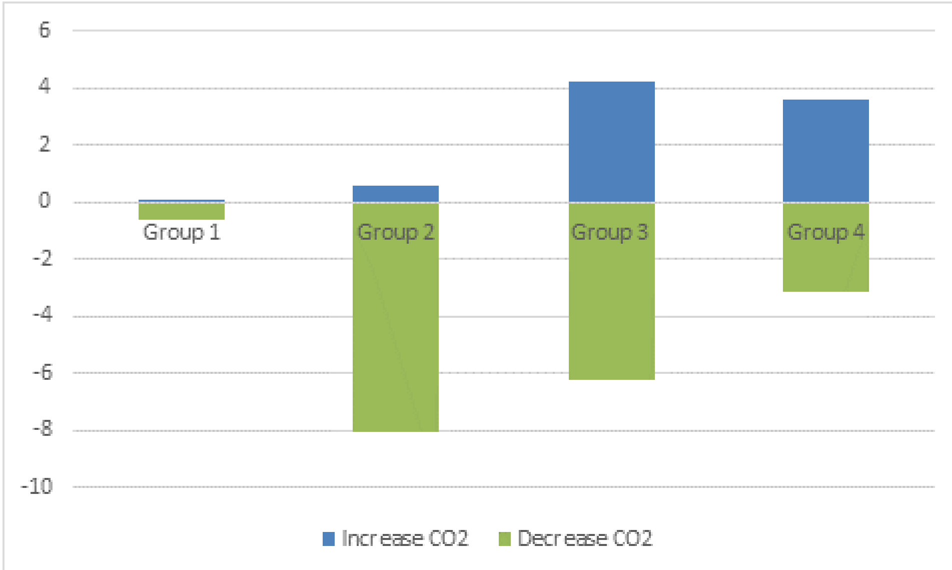

Figure 3-2 Projected Change in CO_2 Emissions at Affected Units in 2025, by Heat Rate Group (million short tons)

Figure 3-3 Projected Change in SO_2 Emissions at Affected Units in 2025, by Heat Rate Group (thousand tons)

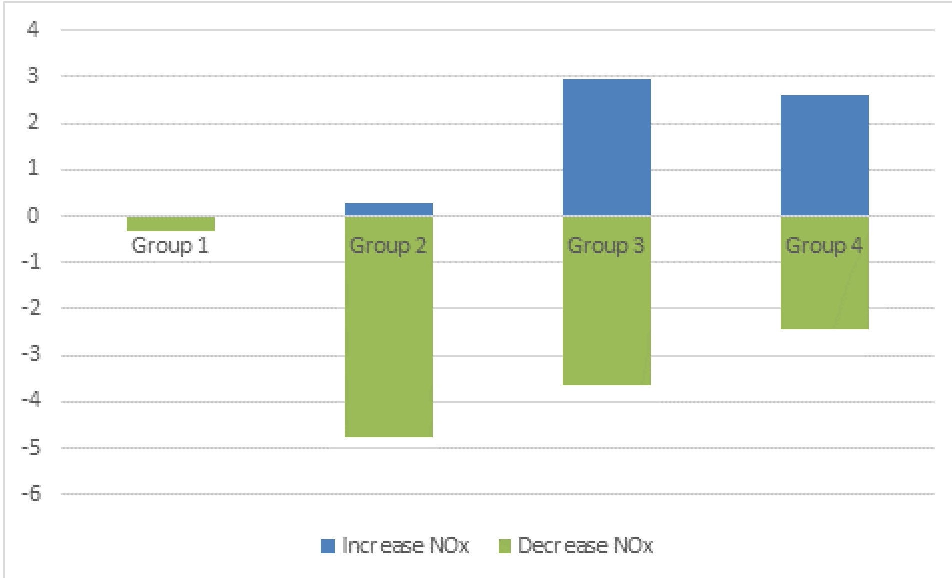

Figure 3-4 Projected Change in Annual NOx Emissions at Affected Units in 2025, by Heat Rate Group (thousand tons)

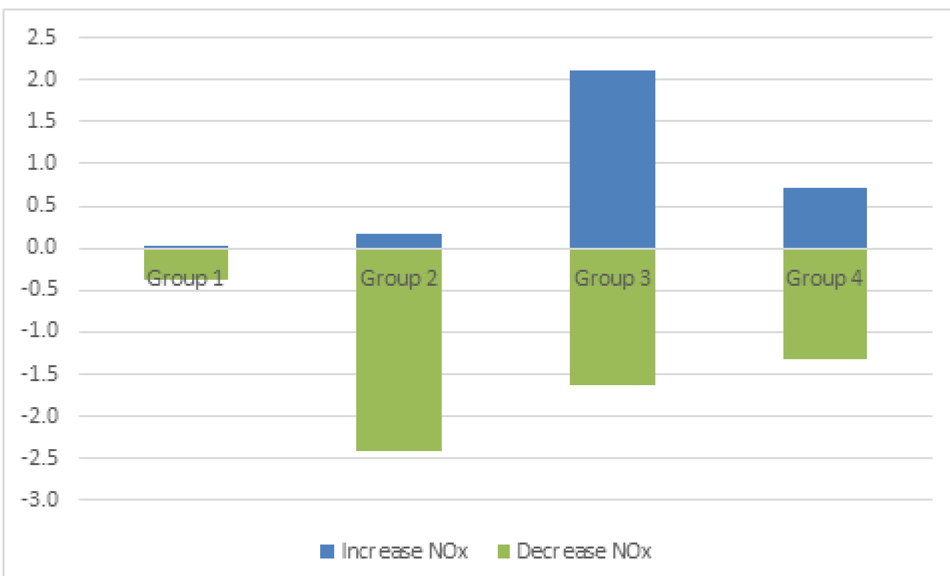

Figure 3-5 Projected Change in Ozone Season NOx Emissions at Affected Units in 2025, by Heat Rate Group (thousand tons)

As described in Chapter 1, coal-fired EGUs decrease their heat rate 0.8 percent to 3.2 percent, which assumes an approach for how each affected source complies with its standard of performance (there are four groups, with three making heat rate improvements). As shown in

Figure 3-1 through Figure 3-5, each Group has many units that decrease emissions and some that increase their emissions of CO_2 and other pollutants, while on net total emissions from the coal-fired EGUs is lower, consistent with their collective fuel efficiency increase. Therefore, consistent with the requirements of the rule, the market modeling shows that units affected by ACE are expected to make small changes in their emissions relative to the baseline. Furthermore, the modeling shows that no set of EGUs that increase or decrease their emissions in each Group has a dominant effect on the total system-wide emissions changes, consistent with the rule and expected market behavior. The system-wide emission reductions are expected to be a small percentage of total emissions, as the emissions changes at each coal unit is small and these changes are diffuse across the coal units in the fleet.[15]

Furthermore, regardless of various sources of uncertainty in baseline market conditions, since all coal units in the baseline would be subject to the regulation and may make incremental changes in their emissions, the emissions changes and market outcomes would be consistent with the baseline population of coal generating units. If there are more coal EGUs in the baseline, there would be more coal EGUs making incremental changes, and the system-wide emissions reductions would likely be higher and commensurate with the greater number of coal units, all else equal.[16] Likewise, if there were fewer coal units, there be lower system-side emissions reductions. Similarly, if units were subject to more or less stringent standards of performance consistent with the application of BSER (relative the assumptions in the illustrative policy scenario), emission reductions as a result of ACE would rise or fall accordingly, but consistent with the range of the standards of performance that could be achieved from the application of HRI that is BSER.

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[15] The emissions from other generating sources not affected by the rule also fall, contributing to system-wide emission reductions. However, as shown in Tables 3-8 through 3-11, the majority of the projected system-wide emission reductions for each pollutant are from emissions changes at coal-fired EGUs >25MW. Given the potential for small increases in generation associated with small changes in fuel efficiency at affected coal EGUs, the reduction in emissions at other generating sources as a result of ACE is expected to be small, regardless of baseline economic conditions and the requirements imposed on each affected coal EGU as a result of ACE.

[16] Hypothetically, even if the reduction or increase in the baseline number of coal units were concentrated amongst those units that increase or decrease their emissions in one of the groups in the illustrative policy scenario, the net effect on total system-wide emissions, and relative to the emissions reductions projected in the illustrative policy scenario, would be small, as indicated by the magnitude of the bars in Figures 3-2 through 3-5. Furthermore, as discussed below, other regulatory and market conditions would likely mitigate notable emissions increases at individual units as a result of ACE.

3.7.4 Projected Generation Mix

Generation by generator type for each of the scenarios is reported in Table 3-12. As can be seen, the illustrative policy scenario shows an overall increase in generation from the coal steam units covered by this final rule, and an overall decrease in generation from natural gas combined cycles. Overall, the absolute changes in generation are very small in the context of total electric generating mix and the uncertainties previously discussed. Figure 3-6 summarizes the information in the table.

Table 3-12 Projected Generation Mix (thousand GWh)

	Baseline	Illustrative Policy Scenario	Percent Change from Baseline
2025			
Coal	915	917	0.3%
NG Combined Cycle (existing)	1,555	1,548	-0.4%
NG Combined Cycle (new)	21	27	24.3%
Combustion Turbine	38	36	-3.8%
Oil/Gas Steam	61	60	-1.5%
Non-Hydro Renewables	583	584	0.3%
Hydro	324	323	-0.1%
Nuclear	643	643	0.0%
Other	41	41	0.1%
Total	4,179	4,179	0.0%
2030			
Coal	878	880	0.2%
NG Combined Cycle (existing)	1,520	1,514	-0.4%
NG Combined Cycle (new)	97	102	5.9%
Combustion Turbine	39	39	-1.9%
Oil/Gas Steam	57	56	-1.4%
Non-Hydro Renewables	730	729	-0.1%
Hydro	326	327	0.2%
Nuclear	604	605	0.1%
Other	41	41	0.3%
Total	4,293	4,293	0.0%
2035			
Coal	780	781	0.1%
NG Combined Cycle (existing)	1,521	1,520	-0.1%
NG Combined Cycle (new)	292	291	-0.4%
Combustion Turbine	54	55	1.0%
Oil/Gas Steam	60	61	2.2%
Non-Hydro Renewables	742	741	-0.1%
Hydro	328	328	0.0%
Nuclear	597	597	0.1%
Other	41	41	0.2%
Total	4,414	4,415	0.0%

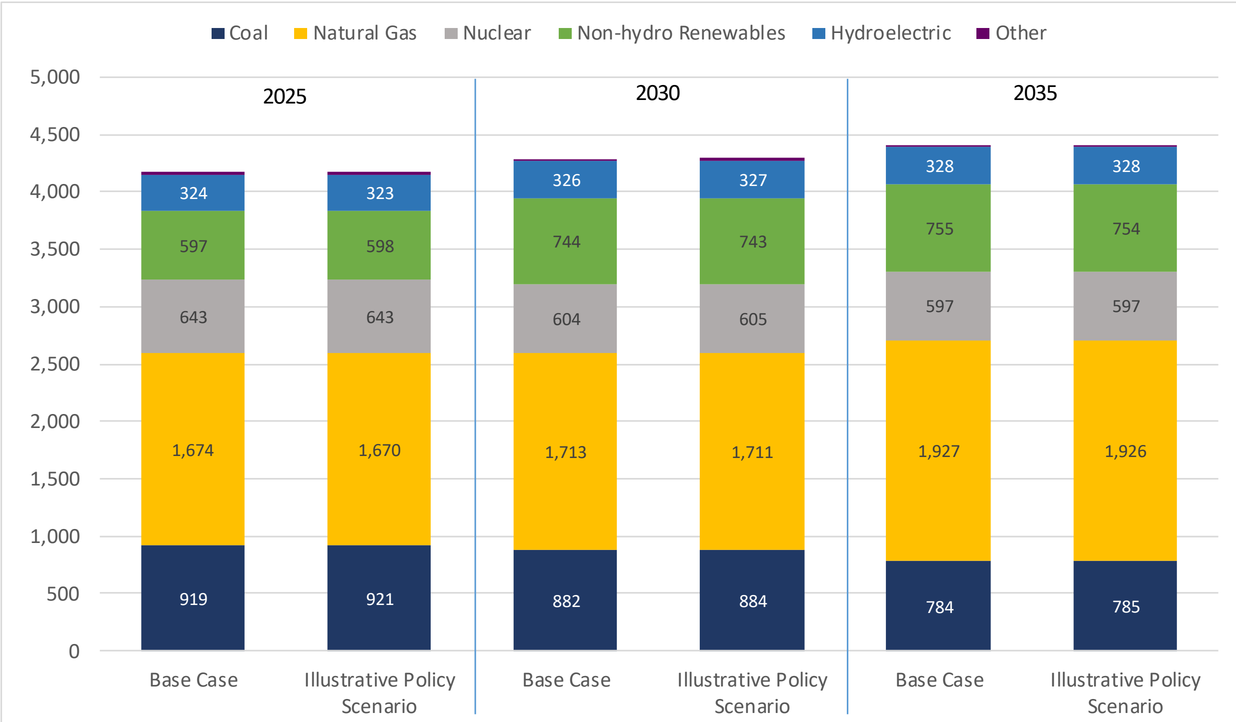

Figure 3-6 Generation Mix (thousand GWh)

3.7.5 Projected Changes to Generating Capacity

Capacity by generator type for the illustrative policy scenario is reported in Table 3-13. Relative to the baseline, the EPA projects a decrease in overall coal capacity of approximately 2 GW or one percent. Commensurately, by 2035, the EPA projects a small increase in operating combustion turbine, renewable, and nuclear capacity. Although the EPA projects a 24 percent increase in new NGCC capacity (~1 GW) relative to the baseline in 2025, the absolute change is relatively small in the context of total electric system operation. There is relatively small or no change in 2030 and 2035, reflecting a temporal shift in projected new NGCC capacity construction. Table 3-14 shows the incremental capacity additions over time in the illustrative policy scenario relative to the baseline for natural gas combined cycle capacity and renewable technologies, which were highlighted in the 2015 CPP RIA. These tables more readily reveal how the temporal flows of these capacity increases differ across the scenarios than the preceding tables.

Table 3-13 Total Generation Capacity by 2025-2035 (GW)

	Baseline	Illustrative Policy Scenario	Percent Change from Baseline
2025			
Coal	172	170	-1.2%
NG Combined Cycle (existing)	262	262	0.0%
NG Combined Cycle (new)	3	4	24.3%
Combustion Turbine	151	151	0.1%
Oil/Gas Steam	72	72	0.5%
Non-Hydro Renewables	210	212	0.5%
Hydro	110	110	0.0%
Nuclear	81	81	0.0%
Other	12	12	0.0%
Total	1,073	1,073	0.0%
2030			
Coal	170	168	-1.2%
NG Combined Cycle (existing)	262	262	0.0%
NG Combined Cycle (new)	12.7	13.4	5.9%
Combustion Turbine	152	152	0.4%
Oil/Gas Steam	72	72	0.5%
Non-Hydro Renewables	266	266	0.1%
Hydro	111	111	0.1%
Nuclear	77	77	0.1%
Other	13	13	0.0%
Total	1,133	1,133	0.0%
2035			
Coal	165	163	-1.0%
NG Combined Cycle (existing)	262	262	0.0%
NG Combined Cycle (new)	38	38	-0.4%
Combustion Turbine	164	165	0.8%
Oil/Gas Steam	72	72	0.5%
Non-Hydro Renewables	270	271	0.0%
Hydro	111	111	0.0%
Nuclear	75	76	0.1%
Other	13	13	0.0%
Total	1,170	1,170	0.0%

Table 3-14 Projected Natural Gas Combined Cycle and Renewable Capacity Additions and Changes Relative to Baseline

	Cumulative Capacity Additions: NGCC (GW)			Cumulative Capacity Additions: Renewables (GW)		
	2025	2030	2035	2025	2030	2035
Baseline	2.8	12.7	38.3	97.7	153.4	158.5
Illustrative Policy Scenario	3.5	13.4	38.1	98.9	153.7	158.6
Incremental	0.7	0.7	-0.1	1.1	0.3	0.1
Percent Change	24.3%	5.9%	-0.4%	1.2%	0.2%	0.1%

3.7.6 Projected Coal Production and Natural Gas Use for the Electric Power Sector

Relative to the baseline, the EPA projects a one percent decrease in annual overall coal production for use by the electric power sector in the illustrative policy scenario over 2025-2035, as shown in Table 3-15, Table 3-16, and Table 3-17. Most of this decrease is projected to occur in production of western subbituminous coals.

Table 3-15 2025 Projected Coal Production for the Electric Power Sector (million short tons)

	Baseline	Illustrative Policy Scenario	Change	Percent Change
Appalachia	64	64	-1	-1.0%
Interior	120	119	-1	-0.6%
West	319	315	-4	-1.2%
Waste Coal	0.24	0.17	-0.07	-28.0%
Total	503	497	-5	-1.1%

Table 3-16 2030 Projected Coal Production for the Electric Power Sector (million short tons)

	Baseline	Illustrative Policy Scenario	Change	Percent Change
Appalachia	55	54	-1	-1.8%
Interior	117	117	-1	-0.6%
West	311	308	-3	-1.0%
Waste Coal	0.19	0.17	-0.02	-10.5%
Total	484	479	-5	-1.0%

Table 3-17 2035 Projected Coal Production for the Electric Power Sector (million short tons)

	Baseline	Illustrative Policy Scenario	Change	Percent Change
Appalachia	35	34	-1	-4.1%
Interior	108	108	0	0.1%
West	291	288	-3	-1.1%
Waste Coal	0.17	0.17	0.00	0.0%
Total	435	430	-4	-1.0%

Relative to the baseline the EPA projects a less than one percent reduction in total gas use in the electric power sector, as shown in Table 3-18.

Table 3-18 Projected Power Sector Gas Use

	Power Sector Gas Use (TCF)		
	2025	**2030**	**2035**
Baseline	11.92	12.11	13.46
Illustrative Policy Scenario	11.88	12.08	13.46
Incremental	-0.04	-0.03	0.00
Percent Change	-0.4%	-0.3%	0.0%

3.7.7 Projected Fuel Price, Market, and Infrastructure Impacts

Relative to the baseline, the illustrative policy scenario results in small changes in electric power sector delivered coal and natural gas prices, on a Btu-weighted average basis. Depending on the year, the EPA projects a very small reduction in delivered natural gas prices on the order of up to one tenth of one percent, as shown in Table 3-19 and Table 3-20.

Table 3-19 Projected Average Minemouth and Delivered Coal Prices (2016$/MMBtu)

	Minemouth			Delivered - Electric Power Sector		
	2025	**2030**	**2035**	**2025**	**2030**	**2035**
Baseline	1.25	1.31	1.38	2.00	2.06	2.10
Illustrative Policy Scenario	1.25	1.31	1.38	2.00	2.06	2.10
Incremental	0.00	0.00	0.00	0.00	0.00	0.00
Percent Change	0.2%	0.0%	-0.1%	0.1%	0.0%	-0.1%

Table 3-20 Projected Average Henry Hub (spot) and Delivered Natural Gas Prices (2016$/MMBtu)

	Henry Hub			Delivered - Electric Power Sector		
	2025	2030	2035	2025	2030	2035
Baseline	3.56	3.64	3.70	3.57	3.60	3.51
Illustrative Policy Scenario	3.56	3.64	3.68	3.57	3.60	3.49
Incremental	0.00	0.00	-0.02	0.00	0.00	-0.02
Percent Change	0.0%	0.0%	-0.6%	0.0%	-0.1%	-0.6%

3.7.8 Projected Retail Electricity Prices

Relative to the baseline, the EPA estimates the impact of the illustrative policy scenario on retail electricity prices to be very small, on average.[17] See Table 3-21. Given the limitations of this analysis, including the uncertainty regarding state implementation and availability of BSER HRI technologies at individual coal-fired EGUs (see Chapter 1 and Section 3.9), the RIA presents retail price projections at a national level. Under the illustrative policy scenario, the EPA projects changes in average retail electricity prices across the contiguous U.S. ranging up to an increase of one-tenth of one percent, relative to the baseline.

Table 3-21 Projected Contiguous U.S. Retail Electricity Prices (cents/kWh), 2025-2035

	2025	2030	2035
Baseline	10.49	10.71	10.83
Illustrative Policy Scenario	10.50	10.72	10.83
Percent Change	0.1%	0.1%	0.0%

3.8 Sensitivity: 45Q Tax Credit Revisions under the Bipartisan Budget Act of 2018

The baseline modeling for this analysis, completed with the EPA's Power Sector Modeling Platform v6 using IPM, does not reflect the revisions to section 45Q tax credits for carbon dioxide sequestration stipulated in the Bipartisan Budget Act of 2018. This legislation provides a credit for sequestered carbon dioxide that increases to $35 per metric tonne by 2026. Preliminary EPA analysis suggests that this credit may have an impact on the future deployment

[17] The electricity price impacts are estimated using the Retail Price Model (RPM) and IPM model outputs. Documentation for the RPM is available at: https://www.epa.gov/airmarkets/epas-power-sector-modeling-platform-v6-using-ipm

of carbon capture and storage technology, and consequently might impact how affected sources might comply with the final rule.

The EPA projects that incorporating the revised 45Q tax credits into the baseline would reduce total electric sector CO_2 emissions between 22 and 24 million short tons annually over the 2025-2035 period. This decrease in electric sector emissions is largely attributable to the sequestration of carbon dioxide projected by IPM at just over 3 GW of projected CCS retrofits at existing coal-fired EGUs. This retrofit capacity is projected by the model to be installed at approximately 8 facilities throughout the contiguous U.S. and is associated with enhanced oil recovery (EOR) at all projected installations. For modeling purposes, the EPA assumes that these retrofits are capable of reducing the CO_2 emissions rate by 90%.[18] The EPA does not expect that that inclusion of this tax credit would have a significant impact on the incremental results presented in this RIA. For further details regarding this scenario, see IPM v6 November 2018 Reference Case with 45Q, available in the docket.

3.9 Limitations of Analysis and Key Areas of Uncertainty

Cost estimates for the illustrative policy scenario are based on rigorous power sector modeling using ICF's Integrated Planning Model. IPM assumes "perfect foresight" of market conditions over the time horizon modeled deterministically; to the extent that utilities and/or energy regulators have different judgments about future conditions affecting the economics of operation or pollution control, costs may be understated or overstated. The modeling reported in this chapter is based on expert judgment of various input assumptions for variables whose outcomes are in fact uncertain, including fuel supplies, technology costs, and electricity demand. As a general matter, the Agency reviews the best available information regarding these and other variables to support a reasonable modeling framework for analyzing the cost, emission changes, and other impacts of regulatory actions.

As previously stated, this analysis is intended to be illustrative, based on a reasonable estimate of how states might apply the BSER taking account of source-specific factors in setting standards of performance, and how sources might comply with those standards. It is important to

[18] For documentation, see https://www.epa.gov/airmarkets/clean-air-markets-power-sector-modeling

note that the EPA has not analyzed or modeled a specific standard of performance, given that this rule establishes BSER, and it is up to states to determine appropriate standards of performance for sources. As such, there is inadequate and incomplete information regarding how states might specifically implement this rule, and the estimated range of costs and impacts presented in this chapter is based on the assumptions described above in this Chapter and in detail in Chapter 1. If sources use compliance options that were not modeled, costs could be lower. Additionally, while the results presented in this RIA indicate the potential for emissions increases at some units in conjunction with making the assumed HRIs (though total emissions are projected to decline), this RIA does not evaluate any potential associated impacts related to New Source Review and how it may mitigate these increases and affect the cost and emissions impacts of this final rule.

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

- Electric demand: The analysis includes an assumption for future electric demand. To the extent electric demand is higher and lower, it may increase/decrease the projected future composition of the fleet.

- Natural gas supply and demand: Large increases in supply over the last few years, and relatively low prices, are represented in the analysis. To the extent prices are higher or lower, it would influence the use of natural gas for electricity generation and overall competitiveness of other EGUs (e.g., coal and nuclear units).

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

These are key uncertainties that may affect the overall composition of electric power generation fleet, and could thus have an effect on the estimated costs and impacts of this action.

However, these uncertainties would affect the modeling of the baseline and illustrative policy scenario similarly, and therefore the impact on the *incremental* projections (reflecting the potential costs/benefits of the illustrative policy scenario) would be more limited and are not likely to result in notable changes to the assessment of ACE found in this chapter.

While it is important to recognize these key areas of uncertainty, they do not change the EPA's overall confidence in the estimated impacts of the illustrative policy scenario presented in this chapter. The EPA continues to monitor industry developments, and makes appropriate updates to the modeling platforms in order to reflect the best and most current data available.

The EPA made different heat rate assumptions in the baseline for this RIA than the illustrative policy scenario. In the baseline the EPA assumed that HRI options (beyond the heat rates already demonstrated at units in recently reported data) were not under active consideration by facility operators in the absence of a regulatory requirement to do so, and this baseline therefore does not represent any endogenous HRI potential.

The analysis in this chapter is limited to the effects of the final rule in the contiguous U.S. The analysis in this RIA excludes the potential costs and emission changes incurred in non-contiguous states and territories from the final rule (as well as the benefits from changes in emissions from and in those areas).[19]

IPM assumes a fixed quantity of electricity demand over the modeling timeframe, which does not change in response to changes in retail electricity prices. In reality, the quantity of electricity demanded may change either through consumer response or the adoption of demand-side energy efficiency programs. Changes in the demand for electricity affect both compliance and social costs. Generally, an assumption that the quantity of electricity demanded does not change with changes in electricity prices leads to higher partial equilibrium estimates of the cost of policy, but this is not always the case. As noted above, the estimated impact on average retail electricity prices under this rule is very small.

[19] The limited exception to this is MR&R costs, as MR&R costs are estimated for 43 states. Five contiguous states are estimated to have no MR&R costs and are expected to submit a negative declaration.

Potential changes in emissions other than emissions of CO_2, SO_2, NO_X and Hg from the electricity sector are not modeled endogenously in IPM and are not reported in this chapter. This includes hazardous air pollutants and direct fine particulate matter ($PM_{2.5}$) emissions and water emissions. Changes in direct $PM_{2.5}$ emissions are modeled using ancillary IPM outputs and other information as described in Chapter 4. Similarly, the potential changes in emissions from producing fuels, such as methane from coal and gas production, are not estimated in this Chapter. Therefore, the associated effects on heath, ecosystems, and visibility from these potential changes in other pollutants from the electricity and other sectors are not quantified in subsequent chapters.

As discussed in the EPA's *Guidelines for Preparing Economic Analyses*, social costs are the total economic burden of a regulatory action. 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 as a result of reallocating some resources related to changes in pollution levels. Estimates of social costs may be compared to the social benefits expected as a result of a regulation to assess its net impact on society. The social costs of a regulatory action will not necessarily be equivalent to the expenditures associated with compliance. Nonetheless, here we use compliance costs as a proxy for social costs. Differences between estimates of social cost include the treatment of tax payments and subsidy receipts, the changes in which are accounted for in compliance costs but would be excluded from the estimate of social costs as they are a transfer. Social costs also include the effect of the regulation on profitability of suppliers to the electricity sector.[20] Also, a social cost estimate would account for how the regulation would affect preexisting distortions in the economy that reduce economic efficiency. Chapter 5 discusses these other potential effects of the regulation and how they may affect the estimates of social costs and benefits.

[20] Much of the social cost borne by electricity consumers is accounted for in the compliance cost estimate as they ultimately will bear part of this cost through changes in electricity prices. Note that this analysis does not identify who ultimately bears the compliance costs, which also include owners of generating assets through changes in their profits.

3.10 References

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CHAPTER 4: ESTIMATED CLIMATE BENEFITS AND HUMAN HEALTH CO-BENEFITS

4.1 Introduction

Implementing the final rule is expected to decrease emissions of carbon dioxide (CO_2) and certain pollutants in the atmosphere that adversely affect human health as compared to the baseline. Pollutant emissions include directly emitted fine particles ($PM_{2.5}$; particles with an aerodynamic diameter of 2.5 microns or smaller), sulfur dioxide (SO_2), oxides of nitrogen (NO_X), and mercury (Hg). SO_2 and NO_X are each a precursor to ambient $PM_{2.5}$, and NO_X emissions are also a precursor in the formation of ambient ground-level ozone.

This chapter describes the methods used to estimate the domestic climate benefits associated with the decrease in CO_2 emissions and domestic health benefits associated with the decrease in $PM_{2.5}$ and ground-level ozone. The EPA refers to the climate benefits as "targeted pollutant benefits" as they reflect the direct benefits of reducing CO_2, and to the ancillary health benefits derived from reductions in emissions other than CO_2 as "co-benefits" as they are not direct benefits from reducing the targeted pollutant. Data, resource, and methodological limitations prevent the EPA from estimating all domestic climate benefits and health and environmental co-benefits, including those from health effects from direct exposure to SO_2, NO_2, and hazardous air pollutants (HAP) including Hg, and ecosystem effects and visibility impairment. We discuss these unquantified effects in Section 4.7.

4.2 Climate Change Impacts

In 2009, the EPA Administrator found that elevated concentrations of greenhouse gases in the atmosphere may reasonably be anticipated both to endanger public health and to endanger public welfare.[1] It is these adverse impacts that necessitate the EPA regulation of GHGs from EGU sources. Since 2009, other science assessments suggest accelerating trends.[2]

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[1] "Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act," 74 Fed. Reg. 66,496 (Dec. 15, 2009) ("Endangerment Finding").
[2] Melillo, Jerry M., Terese (T.C.) Richmond, and Gary W. Yohe, Eds., 2014: Climate Change Impacts in the United States: The Third National Climate Assessment. U.S. Global Change Research Program, 841 pp.

4.3 Approach to Estimating Climate Benefits from CO_2

We estimate the climate benefits from this final rulemaking using a measure of the domestic social cost of carbon (SC-CO_2). The SC-CO_2 is a metric that estimates the monetary value of projected impacts associated with marginal changes in CO_2 emissions in a given year. It includes a wide range of anticipated climate impacts, such as net changes in agricultural productivity and human health, property damage from increased flood risk, and changes in energy system costs, such as reduced costs for heating and increased costs for air conditioning. It is typically used to assess the avoided damages as a result of regulatory actions (i.e., benefits of rulemakings that lead to an incremental reduction in cumulative global CO_2 emissions). The SC-CO_2 estimates used in this RIA focus on the projected impacts of climate change that are anticipated to directly occur within U.S. borders.

The SC-CO_2 estimates presented in this RIA are interim values developed under E.O. 13783 for use in regulatory analyses until an improved estimate of the impacts of climate change to the U.S. can be developed based on the best available science and economics. E.O. 13783 directed agencies to ensure that estimates of the social cost of greenhouse gases used in regulatory analyses "are based on the best available science and economics" and are consistent with the guidance contained in OMB Circular A-4, "including with respect to the consideration of domestic versus international impacts and the consideration of appropriate discount rates" (E.O. 13783, Section 5(c)). In addition, E.O. 13783 withdrew the technical support documents (TSDs) used in the 2015 CPP RIA for describing the global social cost of greenhouse gas estimates developed under the prior Administration as no longer representative of government policy.

Regarding the two analytical considerations highlighted in E.O. 13783 – how best to consider domestic versus international impacts and appropriate discount rates – current guidance in OMB Circular A-4 is as follows. Circular A-4 states that analysis of economically significant proposed and final regulations "should focus on benefits and costs that accrue to citizens and residents of the United States." We follow this guidance by adopting a domestic perspective in our central analysis. Regarding discount rates, Circular A-4 states that regulatory analyses

doi:10.7930/J0Z31WJ2; and USGCRP, 2017: Climate Science Special Report: Fourth National Climate Assessment, Volume I [Wuebbles, D.J., D.W. Fahey, K.A. Hibbard, D.J. Dokken, B.C. Stewart, and T.K. Maycock (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, 470 pp., doi: 10.7930/J0J964J6.

"should provide estimates of net benefits using both 3 percent and 7 percent." The 7 percent rate is intended to represent the average before-tax rate of return to private capital in the U.S. economy. The 3 percent rate is intended to reflect the rate at which society discounts future consumption, which is particularly relevant if a regulation is expected to affect private consumption directly. The EPA follows this guidance below by presenting estimates based on both 3 and 7 percent discount rates in the main analysis. See Chapter 7 for a discussion the modeling steps involved in estimating the domestic SC-CO_2 estimates based on these discount rates. These SC-CO_2 estimates developed under E.O. 13783 presented below will be used in regulatory analysis until more comprehensive domestic estimates can be developed, which would take into consideration recent recommendations from the National Academies of Sciences, Engineering, and Medicine[3] to further update the current methodology to ensure that the SC-CO_2 estimates reflect the best available science.

Table 4-1 presents the average domestic SC-CO_2 estimate across all of the integrated assessment model runs used to estimate the SC-CO_2 for each discount rate for the years 2015 to 2050.[4] As with the global SC-CO_2 estimates, the domestic SC-CO_2 increases over time because future emissions are expected to produce larger incremental damages as physical and economic systems become more stressed in response to greater climatic change, and because GDP is growing over time and many damage categories are modeled as proportional to gross GDP. For emissions occurring in the year 2030, the two domestic SC-CO_2 estimates are $1 and $8 per metric ton of CO_2 emissions (2016$), using a 7 and 3 percent discount rate, respectively.

[3] See National Academies of Sciences, Engineering, and Medicine, Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide, Washington, D.C., January 2017. http://www.nap.edu/catalog/24651/valuing-climate-changes-updating-estimation-of-the-social-cost-of

[4] The SC-CO_2 estimates rely on an ensemble of three integrated assessment models (IAMs): Dynamic Integrated Climate and Economy (DICE) 2010; Climate Framework for Uncertainty, Negotiation, and Distribution (FUND) 3.8; and Policy Analysis of the Greenhouse Gas Effect (PAGE) 2009. See Chapter 7 for an overview of the modeling methodology.

Table 4-1 Interim Domestic Social Cost of CO_2, 2015-2050 (in 2016$ per metric ton)[a]

Year	Discount Rate and Statistic	
	3% Average	7% Average
2015	$6	$1
2020	7	1
2025	7	1
2030	8	1
2035	9	2
2040	9	2
2045	10	2
2050	11	2

[a] These SC-CO_2 values are stated in $/metric ton CO_2 and rounded to the nearest dollar. These values may be converted to $/short ton using the conversion factor 0.90718474 metric tons per short ton for application to the short ton CO_2 emission impacts provided in this rulemaking. Such a conversion does not change the underlying methodology, nor does it change the meaning of the SC-CO_2 estimates. For both metric and short tons denominated SC-CO_2 estimates, the estimates vary depending on the year of CO_2 emissions and are defined in real terms, i.e., adjusted for inflation using the GDP implicit price deflator.

Table 4-2 reports the domestic climate benefits in the three analysis years (2025, 2030, 2035) for the illustrative policy scenario, compared to the baseline.

Table 4-2 Estimated Domestic Climate Benefits, Relative to Baseline (millions of 2016$)[a]

	3% Discount Rate	7% Discount Rate
2025	81	13
2030	81	14
2035	72	13

[a] Values rounded to two significant figures. The SC-CO_2 values are dollar-year and emissions-year specific. SC-CO_2 values represent only a partial accounting of climate impacts.

The limitations and uncertainties associated with the SC-CO_2 analysis, which were discussed at length in the 2015 CPP RIA, likewise apply to the domestic SC-CO_2 estimates presented in this RIA. Some uncertainties are captured within the analysis, as discussed in detail in Chapter 7, while other areas of uncertainty have not yet been quantified in a way that can be modeled. For example, limitations include the incomplete way in which the integrated assessment models capture catastrophic and non-catastrophic impacts, their incomplete treatment of adaptation and technological change, the incomplete way in which inter-regional and inter-sectoral linkages are modeled, uncertainty in the extrapolation of damages to high temperatures, and inadequate representation of the relationship between the discount rate and uncertainty in economic growth over long time horizons. The science incorporated into these models understandably lags behind the most recent research, and the limited amount of research linking climate impacts to economic damages makes this comprehensive global modeling exercise even more difficult. These individual limitations and uncertainties do not all work in the same direction in terms of their influence on the SC-CO_2 estimates. In accordance with guidance in OMB Circular A-4 on the treatment of uncertainty, Chapter 7 provides a detailed discussion of the ways in which the modeling underlying the development of the SC-CO_2 estimates used in this RIA addressed quantified sources of uncertainty and presents a sensitivity analysis to show consideration of the uncertainty surrounding discount rates over long time horizons.

Recognizing the limitations and uncertainties associated with estimating the SC-CO_2, the research community has continued to explore opportunities to improve SC-CO_2 estimates. Notably, the National Academies of Sciences, Engineering, and Medicine conducted a multi-discipline, multi-year assessment to examine potential approaches, along with their relative merits and challenges, for a comprehensive update to the current methodology. The task was to ensure that the SC-CO_2 estimates that are used in Federal analyses reflect the best available science, focusing on issues related to the choice of models and damage functions, climate science modeling assumptions, socioeconomic and emissions scenarios, presentation of uncertainty, and discounting. In January 2017, the Academies released their final report, Assessing Approaches to Updating the Social Cost of Carbon, and recommended specific criteria for future updates to the SC-CO_2 estimates, a modeling framework to satisfy the specified criteria, and both near-term updates and longer-term research needs pertaining to various components of the estimation process (National Academies 2017).[5]

The Academies' 2017 report also discussed the challenges in developing domestic SC-CO_2 estimates, noting that current integrated assessment models do not model all relevant regional interactions – i.e., how climate change impacts in other regions of the world could affect the United States, through pathways such as global migration, economic destabilization, and political destabilization. The Academies concluded that it "is important to consider what constitutes a domestic impact in the case of a global pollutant that could have international implications that impact the United States. More thoroughly estimating a domestic SC-CO_2 would therefore need to consider the potential implications of climate impacts on, and actions by,

[5] National Academies of Sciences, Engineering, and Medicine. 2017. *Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide.* National Academies Press. Washington, DC Available at <https://www.nap.edu/catalog/24651/valuing-climate-damages-updating-estimation-of-the-social-cost-of> Accessed May 30, 2017.

other countries, which also have impacts on the United States." (National Academies 2017, pg. 12-13).

In addition to requiring reporting of impacts at a domestic level, Circular A-4 states that when an agency "evaluate[s] a regulation that is likely to have effects beyond the borders of the United States, these effects should be reported separately" (page 15). This guidance is relevant to the valuation of damages from CO_2 and other GHGs, given that GHGs contribute to damages around the world independent of the country in which they are emitted. Therefore, in accordance with this guidance in OMB Circular A-4, Chapter 7 presents the global climate benefits from this final rulemaking using global SC-CO_2 estimates based on both 3 and 7 percent discount rates. Note the EPA did not quantitatively project the full impact of ACE on international trade and the location of production, so it is not possible to present analogous estimates of international costs resulting from the final action. However, to the extent that the IPM analysis endogenously models international electricity and natural gas trade, and to the extent that affected firms have some foreign ownership, some of the costs accruing to entities outside U.S. borders is captured in the compliance costs presented in this RIA. See Chapter 5 for more discussion of challenges involved in estimating the ultimate distribution of compliance costs.

4.4 Approach to Estimating Human Health Ancillary Co-Benefits

As noted above, this final rule is designed to affect emissions of CO_2 from the EGU sector but will also influence the level of other pollutants emitted in the atmosphere that adversely affect human health; these include 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 EGU emissions associated with the baseline and the illustrative policy scenario are shown in Table 4-3. The change in emissions between the baseline and the illustrative policy scenario will in turn alter the ambient concentrations, population exposure and human health impacts associated with $PM_{2.5}$ and ozone. Finally, ambient concentrations of both SO_2 and NO_X pose health risks independent of $PM_{2.5}$ and ozone, though we do not quantify these impacts in this analysis (U.S. EPA 2016b, 2017).

Table 4-3 Projected EGU Emissions of SO_2, NO_X, and $PM_{2.5}$ [a]

		SO_2	NO_X ozone season[b]	NO_X annual	$PM_{2.5}$
Baseline Emissions (thousand tons)	2025	912.6	386.7	844.4	108.7
	2030	885.6	384.7	810.1	110.1
	2035	817.0	374.3	752.8	113.0
Illustrative Policy Scenario Emissions (thousand tons)	2025	908.5	382.7	837.1	108.1
	2030	879.9	381.4	803.0	109.7
	2035	810.6	370.4	746.8	112.3
Emissions change (Illustrative Policy – Baseline) (thousand tons)	2025	-4.1	-4.0	-7.3	-0.6
	2030	-5.7	-3.3	-7.1	-0.4
	2035	-6.4	-3.9	-6.0	-0.7
Emissions change (Illustrative Policy – Baseline) (%)	2025	-0.4	-1.0	-0.9	-0.6
	2030	-0.6	-0.9	-0.9	-0.4
	2035	-0.8	-1.1	-0.8	-0.6

[a] The SO_2 and NO_X emissions are direct outputs from the IPM simulations as reported in Chapter 3; however, the $PM_{2.5}$ emissions were derived based on IPM-predicted heat rate and other factors as described in Chapter 8.
[b] "ozone season" NO_X emissions refer to total NO_X (ton) emitted during the period of May-September.

This section is a summary of our approach to estimating the incidence and economic value of the $PM_{2.5}$ and ozone-related ancillary co-benefits estimated for this final rule. The Regulatory Impact Analysis (RIA) for the Particulate Matter (PM) National Ambient Air Quality Standards (NAAQS) (U.S. EPA 2012b) the RIA for the Ozone NAAQS (U.S. EPA 2015e) and the user manual for the BenMAP-CE program (U.S. EPA 2018) provide a full discussion of the Agency's approach for quantifying the number and value of estimated air pollution-related impacts. In these documents the reader can find the rationale for selecting health endpoints to quantify; the demographic, health and economic data we apply within the environmental Benefits Mapping and Analysis Program—Community Edition (BenMAP-CE); modeling assumptions; and our techniques for quantifying uncertainty.

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

Implementing the final guidelines will affect the distribution of $PM_{2.5}$ and ozone concentrations throughout the U.S.; this includes locations both meeting and exceeding the NAAQS for PM and ozone. This RIA estimates avoided $PM_{2.5}$- and ozone-related health impacts that are distinct from those reported in the RIAs for both NAAQS (U.S. EPA 2012b, 2015e). The $PM_{2.5}$ and ozone NAAQS RIAs hypothesize, but do not predict, the benefits and costs of strategies that States may choose to enact when implementing a revised NAAQS; these costs and benefits are illustrative and cannot be added to the costs and benefits of policies that prescribe specific emission control measures.

The illustrative policy scenario projects both decreased and increased levels of $PM_{2.5}$ and ozone, depending on the location, compared to the baseline. Furthermore, some portion of the air quality and health benefits from the illustrative policy scenario occur in areas not attaining the $PM_{2.5}$ or Ozone NAAQS, the requirements of which should be accounted for in the baseline. However, the analysis does not account for how interaction with NAAQS compliance would affect the benefits (and costs) of the illustrative policy scenario, which introduces uncertainty in the benefit (and costs) estimates. If the final rule increases or decreases SO_2 and NO_x and consequentially $PM_{2.5}$ and/or ozone, these changes may affect compliance with existing NAAQS standards and subsequently affect the actual benefits and costs of the rule. In the case of areas that do not meet the NAAQS that see decreased concentrations of $PM_{2.5}$ or ozone, states may be able to avoid applying certain other measures to assure NAAQS attainment. As a result, there would be avoided compliance costs and the $PM_{2.5}$ and ozone health and ecological benefits of the rule would likely be lessened. In areas not attaining the NAAQS where $PM_{2.5}$ or ozone concentrations may increase due to the rule, states may instead need to identify additional approaches to reduce emissions from local sources relative to the baseline, thus mitigating any increased $PM_{2.5}$ and ozone concentrations. In this case, the health benefits would be higher and there would be additional costs associated with these additional approaches.

Similarly, the illustrative policy scenario may project increases in $PM_{2.5}$ and ozone concentrations in areas attaining the NAAQS in the baseline. In practice, these potential changes in concentrations may be mitigated by Prevention of Significant Deterioration (PSD) requirements. Again, this RIA does not account for how interaction with NAAQS compliance would affect the benefits and costs of the illustrative policy scenario.

4.4.1 *Air Quality Modeling Methodology*

We performed nationwide photochemical modeling and related analyses to develop spatial fields of air quality across the U.S. for input to BenMAP-CE, which was used to quantify the benefits from this final rule. Spatial fields of air quality were prepared for the baseline and an illustrative policy scenario for each of the following health-impact metrics: annual mean $PM_{2.5}$, May through September seasonal average 8-hour daily maximum (MDA8) ozone, April through October seasonal average 1-hour daily maximum (MDA1) ozone. The illustrative policy scenario reflects EGU emissions analyzed in this final rule RIA. The EGU emissions for the baseline and illustrative policy scenario were obtained from the outputs of the corresponding IPM runs, as described in Chapter 3.

All of the air quality model simulations (i.e., model runs) were performed using the Comprehensive Air Quality Model with Extensions (CAMx)[6] (Ramboll Environ, 2016). Our CAMx nationwide modeling domain (i.e., the geographic area included in the modeling) covers all lower 48 states plus adjacent portions of Canada and Mexico using a horizontal grid resolution of 12 x 12 km. In this section we provide an overview of the air quality modeling and the methodologies we used to develop spatial fields of annual $PM_{2.5}$ and seasonal average ozone concentrations. More information on the air quality modeling platform (inputs and set-up), model performance evaluation for ozone and $PM_{2.5}$, emissions processing for this analysis, and additional details and numerical examples of the methodologies for developing $PM_{2.5}$ and ozone spatial fields are provided in Chapter 8. It should be noted that the air quality modeling platform used in this final action is the same as that used in the RIA for the ACE proposal.

Wherein this rule the Agency employed full-scale photochemical modeling, in some other rules, including the proposed CPP Repeal, EPA applied a benefit per ton approach. A benefit per-ton is a reduced-form approach for relating changes in emissions to estimated counts of premature death and illnesses and the economic value of these impacts (U.S. EPA 2013c). In the proposed CPP repeal, EPA highlighted the difficulty associated with delineating benefits above and below given air quality concentrations predicted by regulatory changes (e.g., above and below the NAAQS and the Lowest Measured Level (LML) in the studies used to derive the

[6] CAMx version 6.40 was used for the modeling to support the proposal RIA. This version of CAMx was the latest public release version of the model at the time this analysis was performed.

concentration response function). At that time, EPA committed to conducting full-scale air quality modeling for the final regulation, and also committed to characterize the uncertainty associated with applying benefit-per-ton estimates by comparing the EPA's approach with a benefits assessment based on full-scale modeling and other reduced-form techniques found in the literature for projecting $PM_{2.5}$ concentrations changes and the associated monetized impacts of those changes (see page 7 of the RIA for the proposed CPP repeal). Over the last year and a half, the EPA systematically compared the changes in benefits, and concentrations where available, from its benefit-per-ton technique and other reduced-form techniques to the changes in benefits and concentration derived from full-form photochemical model representation of a few different specific emissions scenarios.[7] The Agency's goal was to better understand the suitability of alternative reduced-form air quality modeling techniques for estimating the health impacts of criteria pollutant emissions changes in EPA's benefit-cost analysis, including the extent to which reduced form models may over- or under-estimate benefits (compared to full-scale modeling) under different scenarios and air quality concentrations. The scenario-specific emission inputs developed for this project are currently available online.[8] The study design and methodology will be thoroughly described in the final report summarizing the results of the project, which is planned to be completed by the end of 2019.

In the analysis supporting this rule, we conducted several full-scale photochemical model simulations. The modeling included annual model simulations for a 2011 base year and a 2023 future year to provide hourly concentrations of ozone as well as primary and secondarily formed $PM_{2.5}$ component species (e.g., sulfate, nitrate, ammonium, elemental carbon, organic matter, and crustal material) for both years nationwide. The year 2023 was used as the future year because emissions from all anthropogenic source types in the modeling domain for 2023 represent EPA's most up to date future year projections that are available for the analysis of this final rule. As described below, the photochemical modeling results for 2011 and 2023 were part of the inputs used to construct the air quality spatial fields that reflect the influence of EGU

[7] This analysis compared the benefits estimated using full-form photochemical air quality modeling simulations (CMAQ and CAMx) against four reduced-form tools, including: InMAP; AP2/3; EASIUR and the EPA's Benefit per-Ton.
[8] The scenario-specific emission inputs developed for this project are currently available online at: https://github.com/epa-kpc/RFMEVAL Upon completion and publication of the final report, the final report and all associated documentation will be online and available at this URL.

emissions in 2025, 2030, and 2035 on $PM_{2.5}$ and ozone concentrations for the baseline and illustrative policy scenario.[9] Due to timing constraints we did not perform explicit air quality modeling for baseline and illustrative policy scenarios for each of these years. Rather, we used emissions data and the results of the 2011 and 2023 air quality modeling in conjunction with source apportionment modeling for 2023 to estimate the ozone and $PM_{2.5}$ concentrations associated with the baseline and illustrative policy scenario for 2025, 2030 and 2035. In general, source apportionment modeling quantifies the air quality concentrations formed from individual, user-defined groups of emissions sources or "tags". These source tags are tracked through the transport, dispersion, chemical transformation, and deposition processes within the model to obtain hourly gridded[10] contributions from the emissions in each individual tag to hourly modeled concentrations of ozone and $PM_{2.5}$.[11] For this analysis we performed source apportionment modeling for ozone and $PM_{2.5}$ based on 2023 emissions using tools in CAMx[12] to obtain the contributions from EGU emissions as well as other sources to ozone and to $PM_{2.5}$ component species concentrations.[13] The source apportionment method provides an estimate of the effect of changes in emissions from the groups of emissions sources to changes in both $PM_{2.5}$ or ozone concentrations.

The source apportionment modeling was used to quantify the contributions from EGU emissions on a state-by-state or, in some cases, on a multi-state basis. For ozone, we modeled the contributions from the 2023 EGU sector emissions of NO_X and VOC to hourly ozone concentrations for the period April through October to provide data for developing spatial fields for the two seasonal ozone benefits metrics identified above (i.e. for the May-September seasonal average MDA8 ozone and the April-October seasonal average MDA1 ozone). For

[9] 2025, 2030 and 2035 are snapshot years of analysis in this RIA. See Section 1.4.3 of this RIA for further discussion.
[10] Hourly contribution information is provided for each grid cell to provide spatial patterns of the contributions from each tag.
[11] Note that the sum of the contributions in a model grid cell from each tag for a particular pollutant equals the total concentration of that pollutant in the grid cell.
[12] Ozone contributions were modeled using the Ozone Source Apportionment Technique/Anthropogenic Precursor Culpability Assessment (OSAT/APCA) tool and $PM_{2.5}$ component species contributions were modeled using the Particulate Source Apportionment Technique (PSAT) tool as described in "Ramboll Environ, 2016. User's Guide Comprehensive Air Quality Model with Extensions version 6.40. Ramboll Environ International Corporation, Novato, CA."
[13] In the source apportionment modeling for $PM_{2.5}$ we tracked the source contributions from primary, but not secondary organic aerosols (SOA). The method for treating SOA concentrations is described later in this section.

$PM_{2.5}$, we modeled the contributions from the 2023 EGU sector emissions of SO_2, NO_X, and directly emitted $PM_{2.5}$ for the entire year to inform the development of spatial fields of annual mean $PM_{2.5}$. For each state, or multi-state group, we separately tagged EGU emissions depending on whether the emissions were from coal-fired units or non-coal units.[14] In addition to tagging coal-fired and non-coal EGU emissions we also tracked the ozone and $PM_{2.5}$ contributions from the following "domain-wide" tags (i.e., tags that are not geographically grouped by state or multi-state area):

- two tags for emissions from all of those EGUs in the 2023 emissions inventory that were operating in the 2023, but are now expected to retire before 2030[15]; one EGU retirement tag includes emissions from sources that have announced retirements before 2025, and a second tag for EGUs with announced retirements between 2025 and 2030;[16]
- one tag for all U.S. anthropogenic emissions from source sectors other than EGUs;
- one tag for international emissions that are located within the modeling domain, including anthropogenic emissions in Canada, Mexico, as well as offshore marine vessels and drilling platforms;
- one tag that includes emissions from wildfires and prescribed fires;
- one tag for biogenic source emissions; and
- one tag to provide the contributions from concentrations along the outer boundary of the modeling domain.

The development of the EGU tags and the other tags listed above is described in more detail in Chapter 8.

The following data were used to create the spatial fields of ozone and $PM_{2.5}$ concentrations for the baseline and illustrative policy scenario in 2025, 2030, and 2035. Of these inputs, only input 2) has been updated since the analysis for the ACE proposal RIA:

(1) 2023 annual EGU SO_2, NO_X, and directly emitted $PM_{2.5}$ emissions and 2023 ozone season[17] EGU NOx emissions for each EGU tag as described in Chapter 8;

(2) 2025, 2030, and 2035 annual EGU emissions of SO_2, NO_X, and directly emitted $PM_{2.5}$ and EGU ozone season NO_X emissions for the baseline and illustrative policy scenario

[14] For the purposes of this analysis non-coal fuels include emissions from natural gas, oil, biomass, municipal waste combustion and waste coal EGUs.
[15] Note that emissions associated with units in the two EGU retirements tags are not included in the state-level EGU tags (i.e. there is no double-counting of emissions contributions).
[16] At the time of this analysis, there were no announced EGU retirements after 2030.
[17] "Ozone season NO_X emissions" refers to total NO_X (tons) emitted during the period of May-September.

that correspond to each of the 2023 EGU tags defined for the 2023 source apportionment modeling;

(3) Daily 2011 and 2023 modeling-based concentrations of 24-hour average $PM_{2.5}$ component species and MDA1 and MDA8 ozone;

(4) 2023 daily contributions to 24-hour average $PM_{2.5}$ component species and MDA1 and MDA8 ozone from each of the various source tags; and

(5) Base period (2011) "fused surfaces" of measured and modeled air quality[18] representing quarterly average $PM_{2.5}$ component species concentrations and ozone concentrations for the two seasonal average ozone metrics. These "fused surfaces" use the ambient data to adjust modeled fields to match observed data at locations of monitoring sites. Details on the methods for creating fused surfaces are provided in Chapter 8.

Next, we identify the general process for developing the spatial fields for $PM_{2.5}$ using the 2025 baseline as an example to illustrate the procedure. The steps in this process are as follows:

(1) We use the EGU annual SO_2, NO_X, and directly emitted $PM_{2.5}$ emissions[19] for the 2025 baseline and the corresponding 2023 SO_2, NO_X, and directly emitted $PM_{2.5}$ emissions to calculate the ratio of 2025 baseline emissions to 2023 emissions for each of these pollutants for each EGU tag (i.e. a scaling ratio for each pollutant and each tag).

(2) The tag-specific 2025 to 2023 EGU emissions-based scaling ratios from step (1) are multiplied by the corresponding 365 daily 24-hour average $PM_{2.5}$ component species contributions from the 2023 contribution modeling. The emissions ratios for SO_2 are applied to sulfate contributions; ratios for annual NO_X are applied to nitrate contributions; and ratios for directly emitted $PM_{2.5}$ are applied to the EGU contributions to primary organic matter, elemental carbon and crustal material. This step results in 365 adjusted daily $PM_{2.5}$ component species contributions for each EGUs tag that reflects the emissions in the 2025 baseline.

(3) For each individual $PM_{2.5}$ component species, the adjusted contributions for each EGU tag from step (2) are added together to produce a daily EGU tag total. Then the 24-hour average contributions, if any, from units that will retire by 2030 (i.e., the 2025-2030 retirements tag) are included by adding their contribution from the corresponding daily EGU tag total.[20]

(4) The daily total EGU contributions for each $PM_{2.5}$ component species from step (3) are then combined with the species contributions from each of the other source tags, as identified above. As part of this step we also add the total secondary organic aerosol

[18] In this analysis, a "fused surface" represents a spatial field of concentrations of a particular pollutant that was derived by applying the Enhanced Voronoi Neighbor Averaging with adjustment using modeled and measured air quality data (i.e., eVNA) technique (Ding et al. 2016).

[19] The 2025, 2030, and 2035 EGU SO_2 and NO_X emissions for the baseline and illustrative policy scenario were obtained from IPM outputs described in Chapter 3. EGU emissions of directly emitted $PM_{2.5}$ were derived based on heat rate data from the IPM outputs, using a methodology described in Chapter 8.

[20] Note that contributions from units that will retire before 2025 (i.e. the 2025 retirements tag) are not added to the EGU surface since those sources are not expected to have any contributions to $PM_{2.5}$ in 2025.

concentrations from the 2023 modeling to the net EGU contributions of primary organic matter. Note that the secondary organic aerosol concentration does not change between scenarios. This step results in 24-hour average $PM_{2.5}$ component species concentrations for the 2025 baseline in each model grid cell, nationwide for each day in the year.

(5) For each $PM_{2.5}$ component species, we average the daily concentrations from step (4) for each quarter of the year.

(6) The quarterly average $PM_{2.5}$ component species concentrations from step (5)[21] are divided by the corresponding quarterly average species concentrations from the 2011 CAMx model run. This step provides a Relative Response Factor (i.e., RRF) between 2011 and the 2025 baseline for each species in each model grid cell.

(7) The species-specific quarterly RRFs from step (6) are then multiplied by the corresponding species-specific quarterly average concentrations from the base period (2011) fused surfaces to produce quarterly average species concentrations for the 2025 baseline.

(8) The 2025 baseline quarterly average species concentrations from step (7) are summed over the species to produce total $PM_{2.5}$ concentrations for each quarter. Finally, total $PM_{2.5}$ concentrations for the four quarters of the year are averaged to produce the spatial field of annual average $PM_{2.5}$ concentrations for the 2025 baseline that are input to BenMAP-CE.

The steps above are repeated for the baseline in each of the 3 analysis years[22] as well as for the illustrative policy scenario in each year.

For generating the spatial fields for each of the two ozone concentration metrics (MDA1 and MDA8) we follow steps similar to those above for $PM_{2.5}$. Again, we use the 2025 baseline to illustrate the steps for producing ozone spatial fields for each of the cases we analyzed. We use the EGU May through September (i.e., Ozone Season - OS) NO_X for the 2025 baseline and the corresponding 2023 OS NO_X emissions to calculate the ratio of 2025 baseline emissions to 2023 emissions for each EGU tag (i.e. an ozone-season scaling factor for each tag).

(1) We use the EGU ozone season NO_X, emissions[23] for the 2025 baseline and the corresponding 2023 ozone season NO_X emissions to calculate the ratio of 2025 baseline emissions to 2023 emissions for each EGU tag (i.e. a scaling ratio for each tag).

[21] Ammonium concentrations are calculated assuming that the degree of neutralization of sulfate ions remains at 2011 levels (see Chapter 8 for details).

[22] For 2030 and 2035 analysis years, the 2025-2030 retirements tag is not added to the state-level EGU emissions since those sources are not expected to impact $PM_{2.5}$ in those year.

[23] The 2025, 2030, and 2035 EGU NO_X emissions for the baseline and illustrative policy scenario were obtained from IPM outputs described in Chapter 3.

(2) The source apportionment modeling provided separate ozone contributions for ozone formed in VOC-limited chemical regimes (O_3V) and ozone formed in NO_X-limited chemical regimes (O_3N).[24] The tag-specific 2025 to 2023 EGU NO_X emissions-based scaling ratios from step (1) are multiplied by the corresponding O_3N daily contributions to MDA1 and MDA8 concentrations from the 2023 contribution modeling. This step results in adjusted gridded daily MDA1 and MDA8 contributions due to NO_X changes for each EGUs tag that reflect the emissions in the 2025 baseline.

(3) For MDA1 and MDA8, the adjusted contributions for each EGU tag from step (2) are added together to produce a daily EGU tag total. Since IPM does not output VOC from EGUs, there are no predicted changes in VOC emissions in these scenarios so the O_3V contributions remain unchanged. The contributions from the unaltered 2023 O_3V tags are added to the summed adjusted O_3N EGU tags. Finally, the contributions, if any, to MDA1 and MDA8 concentrations from units that will retire by 2030 (i.e., the 2025-2030 retirements tag) are included by adding their contribution from the corresponding daily EGU tag total.[25]

(4) The daily total EGU contributions for MDA1 and MDA8 from step (3) are then combined with the contributions to MDA1 and MDA8 from each of the other source tags. This step results in MDA1 and MDA8 concentrations for the baseline EGU emissions in each model grid cell, nationwide for each day in the ozone season.

(5) For MDA1, we average the daily concentrations from step (4) across all the days in the period April 1 through October 31. For MDA8, we average the daily concentrations across all days in the period May 1 through September 30.

(6) The seasonal mean concentrations from step (5) are divided by the corresponding seasonal mean concentrations from the 2011 CAMx model run. This step provides a Relative Response Factor (i.e., RRF) between 2011 and the 2025 baseline for MDA1 and MDA8 in each model grid cell.

(7) Finally, the RRFs for the seasonal mean metrics from step (6) are then multiplied by the corresponding seasonal mean concentrations from the base period (2011) MDA1 and MDA8 fused surfaces to produce seasonal mean concentrations for MDA1 and MDA8 for the 2025 baseline that are input to BenMAP-CE.

As with $PM_{2.5}$, the steps outlined for ozone are repeated for the baseline in each of the 3 analysis years[26] as well as for the illustrative policy scenario in each year.

As noted above, additional information on the emissions data and analytic steps summarized in this section can be found in Chapter 8. Select maps showing changes in air

[24] Information on the treatment of ozone contributions under NOx-limited and VOC-limited chemical regimes in the CAMx APCA source apportionment technique can be found in the CAMx v6.40 User's Guide (Ramboll, 2016).
[25] Note that contributions from units that will retire before 2025 (i.e. the 2025 retirements tag) are not added to the EGU surface since those sources are not expected to have any contributions to ozone in 2025.
[26] For 2030 and 2035 analysis years, the 2025-2030 retirements tag is not added to the state-level EGU emissions since those sources are not expected to impact ozone in those years.

quality concentrations between the illustrative policy scenario and the baseline are provided later in this chapter.

4.4.2 Estimating $PM_{2.5}$ and Ozone Related Health Impacts

We estimate the quantity and economic value of air pollution-related effects using a "damage-function." This approach quantifies counts of air pollution-attributable cases of adverse health outcomes and assigns dollar values to those counts, while assuming that each outcome is independent of one another. We construct this damage function by adapting primary research—specifically, air pollution epidemiology studies and economic value studies—from similar contexts. This approach is sometimes referred to as "benefits transfer." Below we describe the procedure we follow for: (1) selecting air pollution health endpoints to quantify; (2) calculating counts of air pollution effects using a health impact function; (3) specifying the health impact function with concentration-response parameters drawn from the epidemiological literature.

4.4.2.1 Selecting air pollution health endpoints to quantify

As a first step in quantifying $PM_{2.5}$ and ozone-related human health impacts, the Agency consults the *Integrated Science Assessment for Particulate Matter* (PM ISA) (U.S. EPA 2009) and the *Integrated Science Assessment for Ozone and Related Photochemical Oxidants* (Ozone ISA) (U.S. EPA 2013a). These two documents synthesize the toxicological, clinical and epidemiological evidence to determine whether each pollutant is causally related to an array of adverse human health outcomes associated with either acute (i.e., hours or days-long) or chronic (i.e. years-long) exposure; for each outcome, the ISA reports this relationship to be causal, likely to be causal, suggestive of a causal relationship, inadequate to infer a causal relationship or not likely to be a causal relationship.

In brief, the ISA for $PM_{2.5}$ found acute exposure to $PM_{2.5}$ to be causally related to cardiovascular effects and mortality (i.e., premature death), and respiratory effects as likely-to-be-causally related. The ISA identified cardiovascular effects and total mortality as being causally related to long-term exposure to $PM_{2.5}$ and respiratory effects as likely-to-be-causal; and the evidence was suggestive of a causal relationship for reproductive and developmental effects as well as cancer, mutagenicity and genotoxicity. The ISA for ozone found acute exposure to ozone to be causally related to respiratory effects, a likely-to-be-causal relationship with cardiovascular effects and total mortality and a suggestive relationship for central nervous system effects. Among chronic effects, the ISA reported a likely-to-be-causal relationship for respiratory outcomes and respiratory mortality, and suggestive relationship for cardiovascular effects, reproductive and developmental effects, central nervous system effects, and total mortality.

The Agency estimates the incidence of air pollution effects for those health endpoints above where the ISA classified as either causal or likely-to-be-causal. Table 4-4 reports the effects we quantified and those we did not quantify in this RIA. The list of benefit categories not quantified is not exhaustive. And, among the effects we quantified, we might not have been able to quantify completely either the full range of human health impacts or economic values. The table below omits health effects associated with SO_2, NO_2, and mercury, and any welfare effects such as acidification and nutrient enrichment; these effects are described in Chapters 5 and 6 of the PM NAAQS RIA (U.S. EPA 2012b) and summarized later in this chapter.

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

Category	Effect	Effect Quantified	Effect Monetized	More Information
Premature mortality from exposure to $PM_{2.5}$	Adult premature mortality based on cohort study estimates and expert elicitation estimates (age >25 or age >30)	✓	✓	PM ISA
	Infant mortality (age <1)	✓	✓	PM ISA
Morbidity from exposure to $PM_{2.5}$	Non-fatal heart attacks (age > 18)	✓	✓	PM ISA
	Hospital admissions—respiratory (all ages)	✓	✓	PM ISA
	Hospital admissions—cardiovascular (age >20)	✓	✓	PM ISA
	Emergency room visits for asthma (all ages)	✓	✓	PM ISA
	Acute bronchitis (age 8-12)	✓	✓	PM ISA
	Lower respiratory symptoms (age 7-14)	✓	✓	PM ISA
	Upper respiratory symptoms (asthmatics age 9-11)	✓	✓	PM ISA
	Exacerbated asthma (asthmatics age 6-18)	✓	✓	PM ISA
	Lost work days (age 18-65)	✓	✓	PM ISA
	Minor restricted-activity days (age 18-65)	✓	✓	PM ISA
	Chronic Bronchitis (age >26)	—	—	PM ISA[1]
	Emergency room visits for cardiovascular effects (all ages)	—	—	PM ISA[1]
	Strokes and cerebrovascular disease (age 50-79)	—	—	PM ISA[1]
	Other cardiovascular effects (e.g., other ages)	—	—	PM ISA[2]
	Other respiratory effects (e.g., pulmonary function, non-asthma ER visits, non-bronchitis chronic diseases, other ages and populations)	—	—	PM ISA[2]
	Reproductive and developmental effects (e.g., low birth weight, pre-term births, etc.)	—	—	PM ISA[2,3]
	Cancer, mutagenicity, and genotoxicity effects	—	—	PM ISA[2,3]
Mortality from exposure to ozone	Premature mortality based on short-term study estimates (all ages)	✓	✓	Ozone ISA
	Premature mortality based on long-term study estimates (age 30–99)	✓	✓	Ozone ISA[1]
Morbidity from exposure to ozone	Hospital admissions—respiratory causes (age > 65)	✓	✓	Ozone ISA
	Emergency department visits for asthma (all ages)	✓	✓	Ozone ISA
	Exacerbated asthma (asthmatics age 6-18)	✓	✓	Ozone ISA
	Minor restricted-activity days (age 18–65)	✓	✓	Ozone ISA
	School absence days (age 5–17)	✓	✓	Ozone ISA
	Decreased outdoor worker productivity (age 18–65)	—	—	Ozone ISA[1]
	Other respiratory effects (e.g., premature aging of lungs)	—	—	Ozone ISA[2]
	Cardiovascular and nervous system effects	—	—	Ozone ISA[2]
	Reproductive and developmental effects	—	—	Ozone ISA[2,3]

[1] We assess these co-benefits qualitatively due to data and resource limitations for this analysis. In other analyses we quantified these effects as a sensitivity analysis.
[2] We assess these co-benefits qualitatively because we do not have sufficient confidence in available data or methods.
[3] We assess these co-benefits qualitatively because current evidence is only suggestive of causality or there are other significant concerns over the strength of the association.

4.4.2.2 Calculating counts of air pollution effects using the health impact function

We use the environmental Benefits Mapping and Analysis Program—Community Edition (BenMAP-CE) software program to quantify counts of premature deaths and illnesses attributable to photochemical modeled changes in annual mean $PM_{2.5}$ and summer season average ozone concentrations for the years 2025, 2030 and 2035 using a health impact function (Fann et al. 2017; Hubbell et al. 2005). A health impact function combines information regarding the: concentration-response relationship between air quality changes and the risk of a given adverse outcome; population exposed to the air quality change; baseline rate of death or disease in that population; and, air pollution concentration to which the population is exposed.

The following provides an example of a health impact function, in this case for $PM_{2.5}$ mortality risk. We estimate counts of $PM_{2.5}$-related total deaths (y_{ij}) during each year i (i=2025) among adults aged 30 and older (a) in each county in the contiguous U.S. j (j=1,…,J where J is the total number of counties) as

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

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

where mo_{ija} is the baseline all-cause mortality rate for adults aged a=30-99 in county j in year i stratified in 10-year age groups, β is the risk coefficient for all-cause mortality for adults associated with annual average $PM_{2.5}$ exposure, C_{ij} is the annual mean $PM_{2.5}$ concentration in county j in year i, and P_{ija} is the number of county adult residents aged a=30-99 in county j in year i stratified into 5-year age groups.[27]

The BenMAP-CE tool is pre-loaded with: projected population; projected death rates; recent-year baseline rates of hospital admissions, emergency department visits and other morbidity outcomes; concentration-response parameters; and, economic unit values for each

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

endpoint. $PM_{2.5}$ and ozone concentrations are taken from the air pollution spatial surfaces described above in Section 4.4.1.

This health impact assessment quantifies outcomes using a suite of concentration-response parameters described in the PM NAAQS RIA (U.S. EPA 2012b), Ozone NAAQS RIA (U.S. EPA 2015e) and the user manual for the BenMAP-CE program (U.S. EPA 2018). These documents describe in detail our rationale for selecting air pollution-related health endpoints, the source of the epidemiological evidence, the specific concentration-response parameters applied, and our approach for pooling evidence across epidemiological studies. Given both the severity of air pollution-related mortality and its large economic value, below we describe the source of the concentration-response parameters for this endpoint.

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

For adult PM-related mortality, we use the effect coefficients from two epidemiology studies examining two large population cohorts: the American Cancer Society cohort (Krewski et al. 2009) and the Harvard Six Cities cohort (Lepeule et al. 2012). The Integrated Science Assessment for Particulate Matter (PM ISA) (U.S. EPA 2009) concluded that the analyses of the ACS and Six Cities cohorts provide the strongest evidence of an association between long-term $PM_{2.5}$ exposure and premature mortality with support from additional cohort studies. The SAB's Health Effects Subcommittee (SAB-HES) also supported using effect estimates from these two analyses to estimate the benefits of PM reductions (U.S. EPA-SAB 2010). There are distinct attributes of both the ACS and Six Cities cohort studies that make them well-suited to being used in a PM benefits assessment and so here we present $PM_{2.5}$ related effects derived using relative risk estimates from both cohorts.

The PM ISA, which was twice reviewed by the Clean Air Scientific Advisory Committee of EPA's Science Advisory Board (SAB-CASAC) (EPA-SAB 2008a, 2009), concluded that there is a causal relationship between mortality and both long-term and short-term exposure to $PM_{2.5}$ based on the entire body of scientific evidence. The PM ISA also concluded that the scientific literature supports the use of a no-threshold log-linear model to portray the PM-mortality concentration-response relationship while recognizing potential uncertainty about the exact shape of the concentration-response function. The PM ISA, which informed the setting of the 2012 PM NAAQS, reviewed available studies that examined the potential for a population-level threshold to exist in the concentration-response relationship. Based on such studies, the ISA concluded that the evidence supports the use of a "no-threshold" model and that "little evidence was observed to suggest that a threshold exists" (U.S. EPA 2009) (pp. 2-25 to 2-26). Consistent with this evidence, the Agency historically has estimated health impacts above and below the prevailing NAAQS (U.S. EPA 2010b, 2010c, 2015c, 2015a, 2015d, 2015b, 2016c, 2011c, 2011b, 2012a, 2013b, 2014a, 2014c, 2014b, 2015e).[28]

Following this approach, we report the estimated $PM_{2.5}$-related benefits (in terms of both health impacts and monetized values) calculated using a log-linear concentration-response function that quantifies risk from the full range of simulated $PM_{2.5}$ exposures (NRC 2002; U.S. EPA 2009). When setting the 2012 PM NAAQS, the Administrator also acknowledged greater uncertainty in specifying the "magnitude and significance" of PM-related health risks at PM concentrations below the NAAQS. As noted in the preamble to the 2012 PM NAAQS final rule, the "EPA conclude[d] that it [was] not appropriate to place as much confidence in the magnitude and significance of the associations over the lower percentiles of the distribution in each study as at and around the long-term mean concentration." (78 FR 3154, 15 January 2013). The preamble separately noted that "[a]s both the EPA and CASAC recognize, in the absence of a discernible threshold, health effects may occur over the full range of concentrations observed in the epidemiological studies." (78 FR 3149, 15 January 2013). In general, we are more confident in the size of the risks we estimate from simulated $PM_{2.5}$ concentrations that coincide with the bulk of the observed PM concentrations in the epidemiological studies that are used to estimate the benefits. Likewise, we are less confident in the risk we estimate from simulated $PM_{2.5}$ concentrations that fall below the bulk of the observed data in these studies.[29] To give insight to

[28] The Federal Reference Notice for the 2012 PM NAAQS notes that "[i]n reaching her final decision on the appropriate annual standard level to set, the Administrator is mindful that the CAA does not require that primary standards be set at a zero-risk level, but rather at a level that reduces risk sufficiently so as to protect public health, including the health of at-risk populations, with an adequate margin of safety. On balance, the Administrator concludes that an annual standard level of 12 μg/m3 would be requisite to protect the public health with an adequate margin of safety from effects associated with long- and short-term $PM_{2.5}$ exposures, while still recognizing that uncertainties remain in the scientific information."

[29] The Federal Register Notice for the 2012 PM NAAQS indicates that "[i]n considering this additional population level information, the Administrator recognizes that, in general, the confidence in the magnitude and significance of an association identified in a study is strongest at and around the long-term mean concentration for the air quality distribution, as this represents the part of the distribution in which the data in any given study are generally most concentrated. She also recognizes that the degree of confidence decreases as one moves towards the lower part of the distribution."

the level of uncertainty in the estimated $PM_{2.5}$ mortality benefits at lower ambient concentrations, we report the PM benefits according to alternative concentration cut-points. Below we further describe our rationale for selecting these cut-points. In addition to adult mortality discussed above, we use effect coefficients from a multi-city study to estimate PM-related infant mortality (Woodruff et al. 1997).

4.4.2.4 Quantifying Cases of Ozone-Attributable Premature Death

In 2008, the National Academies of Science (NRC 2008) issued a series of recommendations to the EPA regarding the procedure for quantifying and valuing ozone-related mortality due to short-term exposures. Chief among these was that "…short-term exposure to ambient ozone is likely to contribute to premature deaths" and the committee recommended that "ozone-related mortality be included in future estimates of the health benefits of reducing ozone exposures…" The NAS also recommended that "…the greatest emphasis be placed on the multicity and [National Mortality and Morbidity Air Pollution Studies (NMMAPS)] …studies without exclusion of the meta-analyses" (NRC 2008). Prior to the 2015 Ozone NAAQS RIA, the Agency estimated ozone-attributable premature deaths using an NMMAPS-based analysis (Bell et al. 2004), two multi-city studies (Huang et al. 2004; Schwartz 2005) and effect estimates from three meta-analyses (Bell et al. 2005; Ito et al. 2005; Levy et al. 2005). Beginning with the 2015 Ozone NAAQS RIA, the Agency began quantifying ozone-attributable premature deaths using two newer multi-city studies (Smith et al. 2009; Zanobetti and Schwartz 2008) and one long-term cohort study (Jerrett et al. 2009).[30] We report the ozone-attributable deaths in this RIA as a range reflecting the concentration-response parameters from Smith et al. (2009) on the low end to Jerrett et al. (2009) on the high end.

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[30] Support for modeling long-term exposure-related mortality incidence comes from the ozone ISA as well as recommendations provided by CASAC in their review of the ozone HREA (U.S. EPA-SAB, 2014, p. 3 and 9), despite the lower confidence in quantifying this endpoint because the ISA's consideration of this endpoint is primarily based on one study (Jerrett et al, 2009), though that study is well designed, and because of the uncertainty in that study about the existence and identification of a potential threshold in the concentration-response function. Whereas the ozone ISA concludes that evidence is suggestive of a causal association between total mortality and long-term ozone exposure, specifically with regard to respiratory health effects (including mortality), the ISA concludes that there is likely to be a causal association (U.S. EPA, 2013a). Consistent with the ozone HREA, we use Jerrett et al. (2009) to estimate premature respiratory mortality from long-term ozone exposure.

4.4.3 Economic Value of Ancillary Health Co-benefits

We next quantify the economic value of the $PM_{2.5}$ and ozone-related deaths and illnesses estimated above. Changes in ambient concentrations of air pollution generally yield small changes in the risk of future adverse health effects for a large number of people. Therefore, the appropriate economic measure is willingness to pay (WTP) for changes in risk of a health effect. For some health effects, such as hospital admissions, WTP estimates are not generally available, so we use the cost of treating or mitigating the effect. These cost-of-illness (COI) estimates generally (although not necessarily in every case) understate the true value of reductions in risk of a health effect. They tend to reflect the direct expenditures related to treatment but not the value of avoided pain and suffering from the health effect. The unit values applied in this analysis are provided in Table 5-9 of the PM NAAQS RIA for each health endpoint (U.S. EPA 2012b).

The value of avoided premature deaths account for 98 percent of ancillary monetized PM-related co-benefits and over 90 percent of monetized ozone-related co-benefits. The economics literature concerning the appropriate method for valuing reductions in premature mortality risk is still developing. The value for the projected reduction in the risk of premature mortality is the subject of continuing discussion within the economics and public policy analysis community. Following the advice of the SAB's Environmental Economics Advisory Committee (SAB-EEAC), the EPA currently uses the value of statistical life (VSL) approach in calculating estimates of mortality benefits, because we believe this calculation provides the most reasonable single estimate of an individual's willingness to trade off money for changes in the risk of death (U.S. EPA-SAB 2000). The VSL approach is a summary measure for the value of small changes in the risk of death experienced by a large number of people.

The EPA continues work to update its guidance on valuing mortality risk reductions, and the Agency consulted several times with the SAB-EEAC on this issue. Until updated guidance is available, the Agency determined that a single, peer-reviewed estimate applied consistently, best reflects the SAB-EEAC advice it has received. Therefore, the EPA applies the VSL that was vetted and endorsed by the SAB in the *Guidelines for Preparing Economic Analyses* (U.S. EPA 2016a) while the Agency continues its efforts to update its guidance on this issue. This approach calculates a mean value across VSL estimates derived from 26 labor market and contingent valuation studies published between 1974 and 1991. The mean VSL across these studies is \$6.3 million (2000\$).[31] We then adjust this VSL to account for the currency year and to account for income growth from 1990 to the analysis year. Specifically, the VSLs applied in this analysis in 2016\$ after adjusting for income growth is \$10.5 million for 2025.

The Agency is committed to using scientifically sound, appropriately reviewed evidence in valuing changes in the risk of premature death and continues to engage with the SAB to identify scientifically sound approaches to update its mortality risk valuation estimates. Most recently, the Agency proposed new meta-analytic approaches for updating its estimates (U.S. EPA 2010d), which were subsequently reviewed by the SAB-EEAC. The EPA is taking the SAB's formal recommendations under advisement (U.S. EPA 2017).

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

4.4.4 Characterizing Uncertainty in the Estimated Benefits

This analysis includes many data sources as inputs that are each subject to uncertainty. Input parameters include projected emission inventories, air quality data from models (with their associated parameters and inputs), population data, population estimates, health effect estimates from epidemiology studies, economic data for monetizing co-benefits, and assumptions regarding the future state of the world (i.e., regulations, technology, and human behavior). Uncertainties particular to this analysis include the emissions changes projected in the illustrative

[31] In 1990\$, this base VSL is \$4.8 million.

policy scenario, where we assumed availability of the candidate HRI technologies across the fleet of coal-fired EGUs, the performance standards states would adopt, and the means by which the affected sources would comply with the rule, despite significant uncertainty in these aspects of the final rule.[32] When compounded, even small uncertainties can greatly influence the size of the total quantified benefits.

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

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

As noted above, we assume that the health impact function for fine particles is log-linear without a threshold. Thus, the estimates include health co-benefits from reducing fine particles in areas with different concentrations of $PM_{2.5}$, including both areas that do not meet the fine particle standard and those areas that are in attainment and reflect the full distribution of $PM_{2.5}$ air quality simulated above.

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

In general, we are more confident in the magnitude of the risks we estimate from simulated $PM_{2.5}$ concentrations that coincide with the bulk of the observed PM concentrations in

[32] See Chapter 1 for further discussion of these uncertainties.

the epidemiological studies that are used to estimate the benefits. Likewise, we are less confident in the risk we estimate from simulated $PM_{2.5}$ concentrations that fall below the bulk of the observed data in these studies. There are uncertainties inherent in identifying any particular point at which our confidence in reported associations decreases appreciably, and the scientific evidence provides no clear dividing line. This relationship between the air quality data and our confidence in the estimated risk is represented below in Figure 4-1.

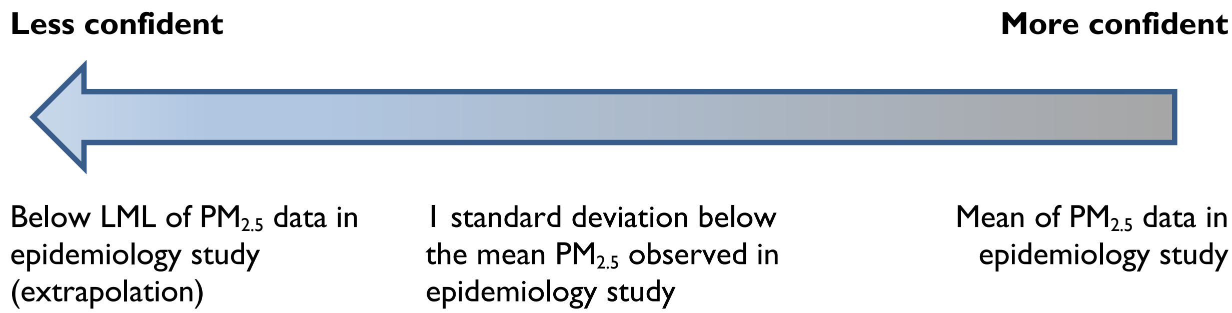

Figure 4-1 Stylized Relationship between the $PM_{2.5}$ Concentrations Considered in Epidemiology Studies and our Confidence in the Estimated PM-related Premature Deaths

In this analysis, we build upon the concentration benchmark approach (also referred to as the Lowest Measured Level analysis) that has been featured in recent RIAs and EPA's *Policy Assessment for Particulate Matter* (U.S. EPA 2011a) by reporting the estimated PM-related deaths according to alternative concentration cutpoints.

Concentration benchmark analyses allow readers to determine the portion of population exposed to annual mean $PM_{2.5}$ levels at or above different concentrations, which provides some insight into the level of uncertainty in the estimated $PM_{2.5}$ mortality benefits. The EPA does not view these concentration benchmarks as concentration thresholds below which we would not quantify health co-benefits of air quality improvements.[33] Rather, the co-benefits estimates reported in this RIA are the most appropriate estimates because they reflect the full range of air quality concentrations associated with the emission reduction strategies being evaluated in this

[33] For a summary of the scientific review statements regarding the lack of a threshold in the $PM_{2.5}$-mortality relationship, see the TSD entitled *Summary of Expert Opinions on the Existence of a Threshold in the Concentration-Response Function for $PM_{2.5}$-related Mortality* (U.S. EPA, 2010b).

final rule. The PM ISA concluded that the scientific evidence collectively is sufficient to conclude that there is a causal relationship between long-term $PM_{2.5}$ exposures and mortality and that overall the studies support the use of a no-threshold log-linear model to estimate mortality attributed to long-term $PM_{2.5}$ exposure (U.S. EPA 2009).

Figure 4-2 reports the percentage of the population, and number of PM-related deaths, both above and below concentration benchmarks in the final policy modeling for the year 2025. The figure identifies the LML for each of the major cohort studies and the annual mean $PM_{2.5}$ NAAQS of 12 $\mu g/m^3$. For Krewski, the LML is 5.8 $\mu g/m^3$ and for Lepeule et al., the LML is 8 $\mu g/m^3$. These results are sensitive to the annual mean $PM_{2.5}$ concentration the air quality model predicted in each 12km by 12km grid cell (see section 4.4.1). The air quality modeling predicts $PM_{2.5}$ concentrations to be at or below the $PM_{2.5}$ NAAQS (12 $\mu g/m^3$) in nearly all locations. The photochemical modeling we employ accounts for the suite of local, state and federal policies expected to reduce $PM_{2.5}$ and $PM_{2.5}$ precursor emissions in future years, such that we project a very small number of locations exceeding the annual standard. After presenting the full suite of results below (Table 4-5) we stratify these estimated $PM_{2.5}$ mortality deaths according to the concentration at which they occurred: below the LML, between the LML and the NAAQS, and above the NAAQS in future years across different policy scenarios (Table 4-8). The results above should be viewed in the context of the air quality modeling technique we used to estimate $PM_{2.5}$ concentrations. As described in Chapter 8 and above, we are more confident in our ability to use the air quality modeling technique described above to estimate *changes* in annual mean $PM_{2.5}$ concentrations than we are in our ability to estimate *absolute* $PM_{2.5}$ concentrations.

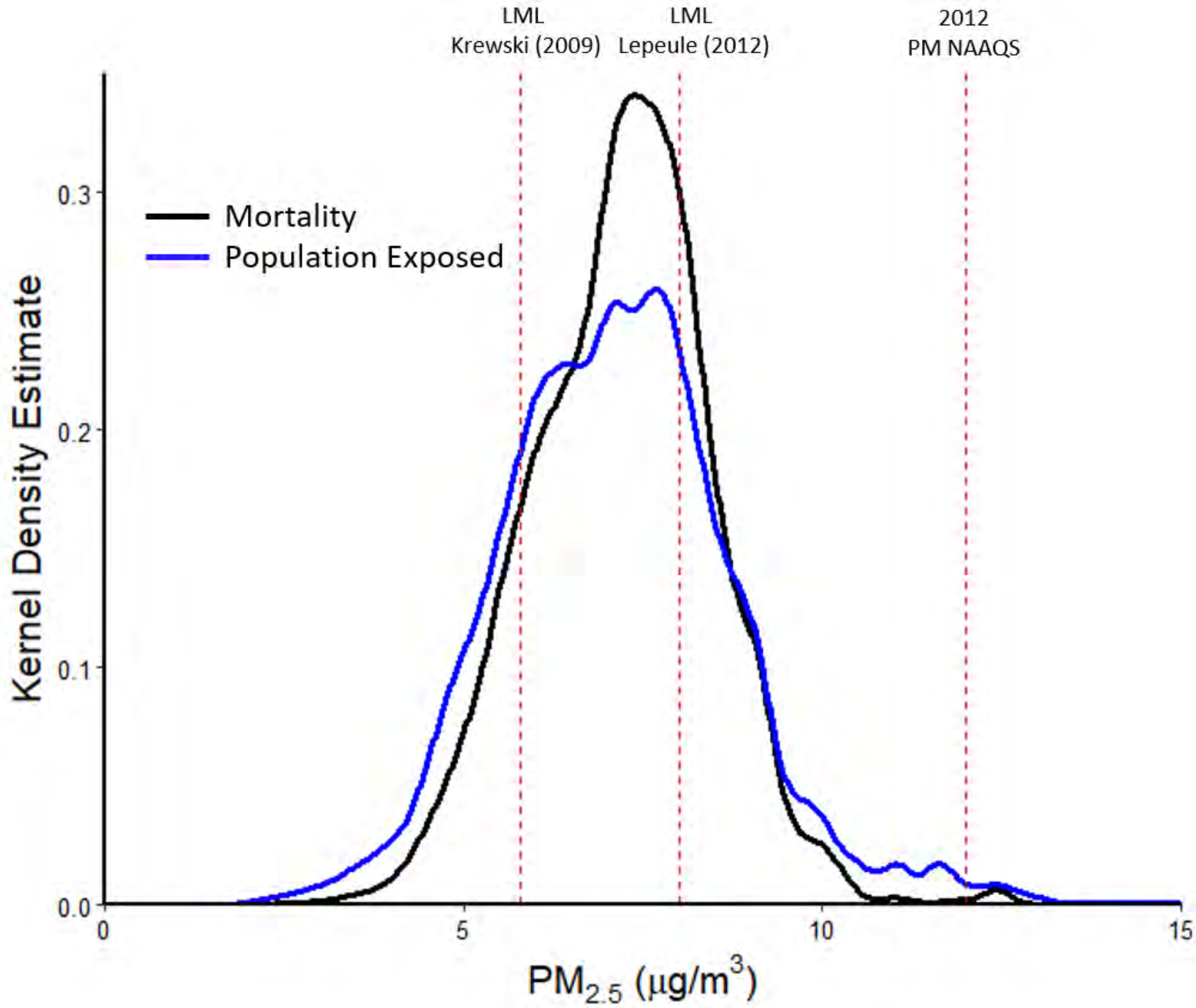

Figure 4-2 Estimated Percentage of $PM_{2.5}$-Related Deaths and Number of Individuals Exposed by Annual Mean $PM_{2.5}$ Level in 2025

4.5 Air Quality and Health Impact Results

4.5.1 Air Quality Results

Below we present the model-predicted change in annual mean $PM_{2.5}$ concentrations and summer-season average daily 8 hour maximum ozone concentrations for the illustrative policy scenario (Figure 4-3). All maps display the change in air pollution calculated as the policy case minus the baseline. The spatial fields used to create these maps serve as an input to the benefits analysis, the results of which are described further below.

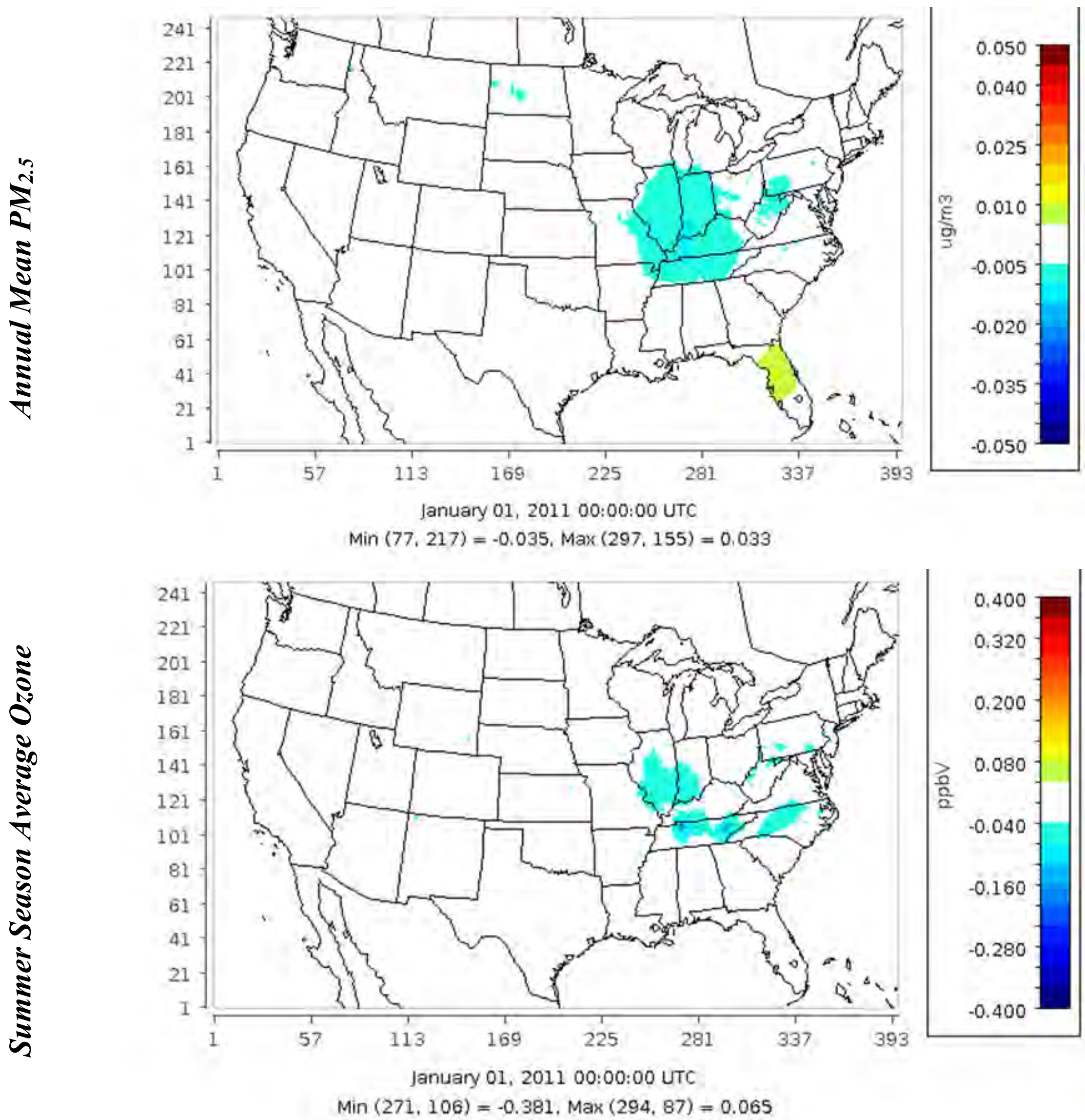

Figure 4-3 Change in Annual Mean PM2.5 (µg/m^3) and Summer Season Average Daily 8hr Maximum Ozone (ppb) in 2025 (Difference Calculated as Illustrative Policy Scenario minus Baseline)

4.5.1 Estimated Number and Economic Value of Ancillary Health Co-Benefits

Below we report the estimated number of reduced $PM_{2.5}$ and ozone-related premature deaths and illnesses in each year (Table 4-5) relative to the baseline along with the 95% confidence interval. The number of reduced estimated deaths and illnesses from the illustrative policy scenario are calculated from the sum of individual reduced mortality and illness risk across the population. The table below is followed by the estimated number of avoided $PM_{2.5}$-

related premature deaths calculated using different approaches to help the reader determine the fraction of $PM_{2.5}$ attributable deaths occuring at lower ambient concentrations. We summarize the dollar value of these impacts for the illustrative policy scenario across all $PM_{2.5}$ and ozone-related premature deaths and illnesses, using alternative approaches to representing and quantifying PM mortality risk effects (Table 4-7).

When estimating benefits at or above the PM NAAQS, the percentage of total benefits attributable to reducing PM exposure ranges from 5 percent to 9 percent, with the remainder being attributable to reducing ozone exposure. When estimating benefits at or above the Lowest Measured Levels of the two long-term exposure cohort studies, the percentage of total benefits attributable to reducing PM ranges from 51 percent to 80 percent, with the remainder being attributable to reducing ozone exposure. Finally, when estimating the benefits using the no-threshold approach, the percentage of total benefits attributable to reducing PM ranges from 78 percent to 81 percent, with the remainder being attributable to reducing ozone.

The alternative approaches to quantifying and presenting mortality risk effects include both different means for quantifying expected impacts using concentration-response functions over the entire domain of exposure (i.e., the no-threshold model) along with different means of presenting impacts by limiting consideration to only those impacts at exposures above the LML or above the NAAQS (Table 4-8; Table 4-9; Figure 4-4).[34]

[34] The EPA continues to refine its approach for estimating and reporting PM-related effects at lower concentrations, particularly at levels below those considered by the long-term exposure epidemiology studies used here to quantify PM-related premature deaths. The Agency acknowledges the additional uncertainty associated with effects estimated at these lower levels (particularly below the LML of the long-term exposure mortality studies) and seeks to develop quantitative approaches for reflecting this uncertainty in the estimated PM benefits.

Table 4-5 Estimated Avoided $PM_{2.5}$ and Ozone-Related Premature Deaths and Illnesses in 2025, 2030 & 2035 (95% Confidence Interval) [a]

		2025	2030	2035
Avoided premature death among adults				
$PM_{2.5}$	Krewski *et al.* (2009)	33 (22 to 43)	44 (30 to 58)	48 (32 to 63)
	Lepeule *et al.* (2012)	74 (37 to 110)	99 (49 to 150)	110 (54 to 160)
Ozone	Smith *et al.* (2009)	6 (3 to 9)	6 (3 to 9)	7 (4 to 11)
	Jerrett et al. (2009)	23 (8 to 38)	23 (8 to 38)	28 (9 to 46)
$PM_{2.5}$- related non-fatal heart attacks among adults				
	Peters et al. (2001)	37 (9 to 64)	48 (12 to 84)	50 (12 to 88)
	Pooled estimate	4 (2 to 11)	5 (2 to 14)	5 (2 to 14)
All other morbidity effects				
	Hospital admissions—cardiovascular ($PM_{2.5}$)	9 (4 to 16)	12 (5 to 22)	13 (5 to 23)
	Hospital admissions—respiratory ($PM_{2.5}$ & O_3)	19 ((6) to 40)	23 ((7) to 48)	25 ((8) to 53)
	ED visits for asthma ($PM_{2.5}$ & O_3)	54 ((3) to 150)	55 ((5) to 150)	65 ((5) to 180)
	Exacerbated asthma ($PM_{2.5}$ & O_3)	14,000 ((11,000) to 35,000)	14,000 ((11,000) to 34,000)	17,000 ((13,000) to 41,000)
	Minor restricted-activity days ($PM_{2.5}$ & O_3)	48,000 (28,000 to 67,000)	52,000 (32,000 to 71,000)	58,000 (36,000 to 80,000)
	Acute bronchitis ($PM_{2.5}$)	42 ((10) to 94)	56 ((13) to 130)	60 ((14) to 130)
	Upper resp. symptoms ($PM_{2.5}$)	770 (140 to 1,400)	1,000 (190 to 1,900)	1,100 (200 to 2,000)
	Lower resp. symptoms ($PM_{2.5}$)	540 (200 to 870)	720 (270 to 1,200)	770 (290 to 1,200)
	Lost work days ($PM_{2.5}$)	3,700 (3,100 to 4,200)	4,600 (3,900 to 5,400)	5,000 (4,300 to 5,800)
	School absence days (O_3)	8,400 (3,000 to 19,000)	8,200 (2,900 to 18,000)	9,700 (3,400 to 22,000)

[a] Values rounded to two significant figures.

Table 4-6 Estimated Avoided PM-Related Premature Deaths Using Alternative Approaches Using Two Approaches to Quantifying Avoided PM-Attributable Deaths (95% Confidence Interval) in 2025, 2030 & 2035 [a]

Log-Linear no-threshold model	**2025**	**2030**	**2035**
Krewski *et al.* (2009)	33 (22 to 43)	44 (30 to 58)	48 (32 to 63)
Lepeule *et al.* (2012)	74 (37 to 110)	99 (49 to 150)	110 (54 to 160)
Quantifying effect of $PM_{2.5}$ above the LML in each study			
Krewski *et al.* (2009) (LML= 5.8 $\mu g/m^3$)	31 (21 to 41)	39 (26 to 51)	41 (28 to 55)
Lepeule *et al.* (2012) (LML=8$\mu g/m^3$)	23 (12 to 35)	28 (14 to 42)	31 (16 to 47)

[a] Values rounded to two significant figures

Table 4-7 Estimated Economic Value of Avoided $PM_{2.5}$ and Ozone-Attributable Deaths and Illnesses for the Illustrative Policy Scenario Using Alternative Approaches to Represent $PM_{2.5}$ Mortality Risk Effects (95% Confidence Interval; millions of 2016$)[a]

		2025			2030			2035		
Ozone benefits summed with PM benefits:										
3% Discount Rate	No-threshold model[b]	$390 ($37 to $1,100)	*to*	$970 ($86 to $2,800)	$490 ($47 to $1,300)	*to*	$1,200 ($110 to $3,500)	$550 ($52 to $1,500)	*to*	$1,400 ($120 to $3,900)
	Limited to above LML[c]	$370 ($36 to $1,000)	*to*	$480 ($42 to $1,400)	$440 ($42 to $1,200)	*to*	$520 ($47 to $1,500)	$480 ($25 to $1,300)	*to*	$610 ($16 to $1,800)
	Effects above NAAQS[d]	$76 ($8 to $210)	*to*	$250 ($23 to $760)	$75 ($8 to $210)	*to*	$260 ($23 to $770)	$90 ($10 to $250)	*to*	$320 ($28 to $930)
Ozone benefits summed with PM benefits:										
7% Discount Rate	No-threshold model[b]	$360 ($34 to $990)	*to*	$900 ($80 to $2,600)	$460 ($44 to $1,200)	*to*	$1,100 ($100 to $3,200)	$510 ($48 to $1,400)	*to*	$1,300 ($110 to $3,600)
	Limited to above LML[c]	$350 ($33 to $950)	*to*	$460 ($41 to $1,300)	$410 ($39 to $1,100)	*to*	$500 ($44 to $1,400)	$450 ($22 to $1,200)	*to*	$590 ($13 to $1,700)
	Effects above NAAQS[d]	$76 ($8 to $210)	*to*	$250 ($22 to $760)	$75 ($8 to $210)	*to*	$260 ($23 to $770)	$90 ($10 to $250)	*to*	$320 ($28 to $930)

[a] Values rounded to two significant figures.

[b] PM effects quantified using a no-threshold model. Low end of range reflects dollar value of effects quantified using concentration-response parameter from Krewski et al. (2009) and Smith et al. (2008) studies; upper end quantified using parameters from Lepeule et al. (2012) and Jerrett et al. (2009). Full range of ozone effects is included, and ozone effects range from 19% to 22% of the estimated values.

[c] PM effects quantified at or above the Lowest Measured Level of each long-term epidemiological study. Low end of range reflects dollar value of effects quantified down to LML of Krewski et al. (2009) study (5.8 $\mu g/m^3$); high end of range reflects dollar value of effects quantified down to LML of Lepeule et al. (2012) study (8 $\mu g/m^3$). Full range of ozone effects is still included, and ozone effects range from 20% to 49% of the estimated values.

[d] PM effects only quantified at or above the annual mean of 12 to provide insight regarding the fraction of benefits occurring above the NAAQS. Range reflects effects quantified using concentration-response parameters from Smith et al. (2008) study at the low end and Jerrett et al. (2009) at the high end. Full range of ozone effects is still included, and ozone effects range from 91% to 95% of the estimated values.

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Table 4-8 Estimated Percent of Avoided $PM_{2.5}$-related Premature Deaths Above and Below $PM_{2.5}$ Concentration Cut Points

Year	Epidemiological study	Total mortality	Avoided $PM_{2.5}$-related premature deaths reported by air quality cutpoint		
			Above NAAQS	*Below NAAQS and Above LML* [a]	*Below LML* [a]
2025	Krewski	33	<1 *(<1%)*	31 *(94%)*	1.5 *(5%)*
	Lepeule	74	<1 *(<1%)*	23 *(31%)*	51 *(69%)*
2030	Krewski	44	<1 *(<1%)*	38 *(86%)*	5.2 *(12%)*
	Lepeule	99	<1 *(<1%)*	27 *(27%)*	71 *(72%)*
2035	Krewski	48	<1 *(<1%)*	41 *(85%)*	6.3 *(13%)*
	Lepeule	110	<1 *(<1%)*	31 *(28%)*	78 *(71%)*

[a] The LML of the Krewski study is 5.8 µg/m^3 and 8 µg/m^3 for Lepeule et al study.

Table 4-9 Avoided $PM_{2.5}$-related Premature Deaths Estimated at Annual Mean $PM_{2.5}$ Levels Corresponding to the Air Quality Distribution Observed in the Krewski et al. (2009) American Cancer Society Study

Year	Below LML (<5.8)	LML to 1st %ile (≥5.8 & <6.7)	1st to 5th %ile (≥6.7 & <8.8)	5th to 10th %ile (≥8.8 & <10.2)	10th to 25th %ile (≥10.2 & <11.8)	25th %ile & Above (≥11.8)
2025	2 (1 to 2)	5 (4 to 7)	22 (15 to 30)	3 (2 to 4)	0 (0 to 0)	0 (0 to 0)
2030	5 (4 to 7)	8 (5 to 10)	26 (18 to 35)	4 (3 to 5)	0 (0 to 0)	0 (0 to 0)
2035	6 (4 to 8)	9 (6 to 12)	28 (19 to 37)	4 (3 to 6)	0 (0 to 0)	0 (0 to 0)

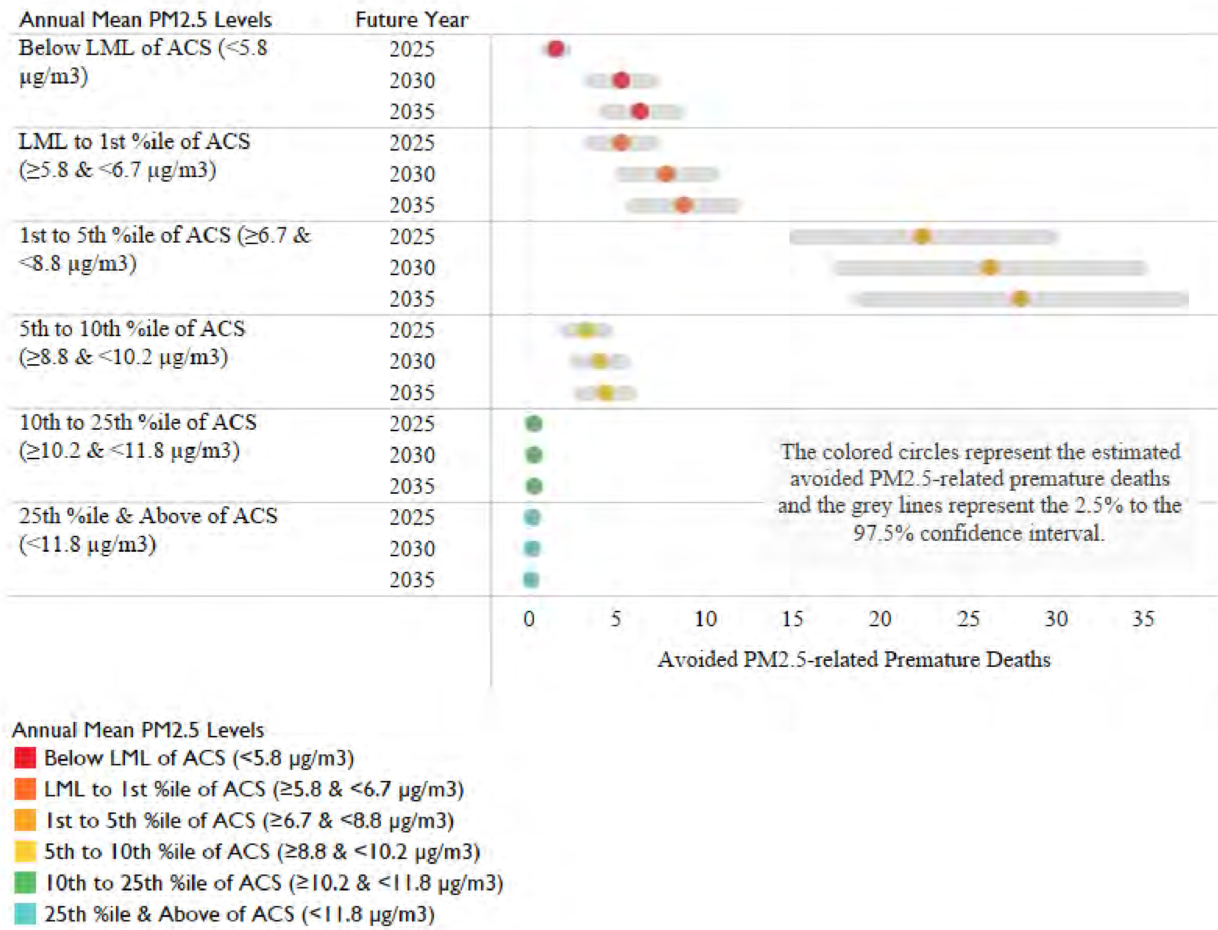

Figure 4-4 Avoided PM2.5-related Premature Deaths Estimated at Annual Mean $PM_{2.5}$ Levels Corresponding to the Air Quality Distribution Observed in the Krewski et al. (2009) American Cancer Society Study (ACS)

The estimated number of deaths above and below the LML varies considerably according to the epidemiology study used to estimate risk. Thus, for any year analyzed, we estimate a substantially larger fraction of PM-related deaths above the LML of the Krewski et al. (2009) study than we do the Lepeule et al. (2012) study as shown in Table 4-8. Likewise, we estimate a greater percentage of $PM_{2.5}$-related deaths below the LML of the Lepeule et al. (2012) study than we do the Krewski et al. (2009) study. Table 4-8 also shows we estimate a very small percentage of PM-related premature deaths occurring above the NAAQS in any future year using either of these two studies.

4.6 Total Estimated Climate and Health Benefits

In this analysis, we estimated the dollar value of changes in CO_2 emissions and the ancillary co-benefits of changes in exposure to $PM_{2.5}$ and ozone, but were unable to quantify the economic value of changes in exposure to mercury, carbon monoxide, SO_2, and NO_2, ecosystem effects or visibility impairment. Table 4-10 through Table 4-12 report the combined domestic climate benefits, and health co-benefits discounted at rates of 3 percent and 7 percent for the illustrative policy scenario evaluated for each analysis year: 2025, 2030, and 2035.

Table 4-10 Estimated Climate Benefits and Ancillary Health Co-Benefits of Illustrative Policy Scenario (millions of 2016$)

	Values Calculated using 3% Discount Rate			Values Calculated using 7% Discount Rate		
	Domestic Climate Benefits	**Health Co-Benefits**	**Total Benefits**	**Domestic Climate Benefits**	**Health Co-Benefits**	**Total Benefits**
2025	81	390 to 970	470 to 1,000	13	360 to 900	370 to 920
2030	81	490 to 1,200	570 to 1,300	14	460 to 1,100	470 to 1,100
2035	72	550 to 1,400	620 to 1,400	13	510 to 1,300	520 to 1,300

Notes: Estimates rounded to two significant figures, so figures may not sum due to independent rounding. The climate benefit estimates in this table reflect the value of domestic impacts from CO_2 emission changes and do not account for changes in non-CO_2 GHG emissions. Ozone co-benefits occur in analysis year, so they are the same for all discount rates. The health co-benefits reflect the sum of the $PM_{2.5}$ and ozone co-benefits and reflect the range based on adult mortality functions (e.g., from Krewski *et al.* (2009) with Smith *et al.* (2009) to Lepeule *et al.* (2012) with Jerrett et al. (2009)). The health co-benefits do not account for direct exposure to NO_2, SO_2, and HAP; ecosystem effects; or, visibility impairment.

Table 4-11 Estimated Climate Benefits and Ancillary Health Co-Benefits of Illustrative Policy Scenario, showing only $PM_{2.5}$ Related Mortality Risk Benefits above the Lowest Measured Level of Each Long-Term $PM_{2.5}$ Mortality Study (millions of 2016$)

	Values Calculated using 3% Discount Rate			Values Calculated using 7% Discount Rate		
	Domestic Climate Benefits	Health Co-Benefits	Total Benefits	Domestic Climate Benefits	Health Co-Benefits	Total Benefits
2025	81	370 to 480	450 to 560	13	350 to 460	360 to 470
2030	81	440 to 520	520 to 600	14	410 to 500	420 to 510
2035	72	480 to 610	560 to 680	13	450 to 590	460 to 600

Notes: Estimates rounded to two significant figures, so figures may not sum due to independent rounding. The climate benefit estimates in this table reflect the value of domestic impacts from CO_2 emission changes and do not account for changes in non-CO_2 GHG emissions. Ozone co-benefits occur in analysis year, so they are the same for all discount rates. The health co-benefits reflect the sum of the $PM_{2.5}$ and ozone co-benefits and reflect the range based on adult mortality functions (e.g., from Krewski *et al.* (2009) with Smith *et al.* (2009) to Lepeule *et al.* (2012) with Jerrett et al. (2009)). The health co-benefits do not account for direct exposure to NO_2, SO_2, and HAP; ecosystem effects; or, visibility impairment.

Table 4-12 Estimated Climate Benefits and Ancillary Health Co-Benefits of Illustrative Policy Scenario, showing only $PM_{2.5}$ Related Mortality Risk Benefits above $PM_{2.5}$ National Ambient Air Quality Standard (millions of 2016$)

	Values Calculated using 3% Discount Rate			Values Calculated using 7% Discount Rate		
	Domestic Climate Benefits	Health Co-Benefits	Total Benefits	Domestic Climate Benefits	Health Co-Benefits	Total Benefits
2025	81	76 to 250	160 to 330	13	76 to 250	89 to 270
2030	81	75 to 260	160 to 340	14	75 to 260	89 to 270
2035	72	90 to 320	160 to 390	13	90 to 320	100 to 330

Notes: Estimates rounded to two significant figures, so figures may not sum due to independent rounding. The climate benefit estimates in this table reflect the value of domestic impacts from CO_2 emission changes and do not account for changes in non-CO_2 GHG emissions. Ozone co-benefits occur in analysis year, so they are the same for all discount rates. The health co-benefits reflect the sum of the $PM_{2.5}$ and ozone co-benefits and reflect the range based on adult mortality functions (e.g., from Krewski *et al.* (2009) with Smith *et al.* (2009) to Lepeule *et al.* (2012) with Jerrett et al. (2009)). The health co-benefits do not account for direct exposure to NO_2, SO_2, and HAP; ecosystem effects; or, visibility impairment.

4.7 Ancillary Co-Benefits Not Quantified

The monetized co-benefits estimated above are a subset of those we expect to occur. Data, time, and resource limitations prevented the EPA from quantifying the impacts to, or monetizing the co-benefits from, several important benefit categories; these include co-benefits associated with exposure to several HAPs (including mercury and hydrogen chloride), SO_2 and

NO_2, as well as ecosystem effects, and visibility impairment. Below is a qualitative description of these benefits (Table 4-13).

We group endpoints effected by these pollutants into “health” and “welfare” categories. These are legal terms used in the context of setting the primary and secondary NAAQS standards and come from the Clean Air Act (CAA). The primary standards are based on human health considerations while the secondary standards are based on welfare considerations, which essentially are non-human health impacts that may be considered when setting a secondary NAAQS standard (e.g., ecosystem effects, visibility impairment, material damage). The definition of the term welfare used in this section is not the same as the term is commonly applied in benefit-cost analysis, which is as a measure of individual well-being that accounts for both health and non-health outcomes. While the CAA only applies these terms to criteria pollutants, they are applied here to both criteria and non-criteria pollutants.

Table 4-13 Unquantified Ancillary Health and Welfare Co-Benefits Categories

Category	Effect	Effect Quantified	Effect Monetized	More Information
Improved Human Health				
Reduced incidence of morbidity from exposure to NO_2	Asthma hospital admissions (all ages)	—	—	NO_2 ISA[1]
	Chronic lung disease hospital admissions (age > 65)	—	—	NO_2 ISA[1]
	Respiratory emergency department visits (all ages)	—	—	NO_2 ISA[1]
	Asthma exacerbation (asthmatics age 4–18)	—	—	NO_2 ISA[1]
	Acute respiratory symptoms (age 7–14)	—	—	NO_2 ISA[1]
	Premature mortality	—	—	NO_2 ISA[1,2,3]
	Other respiratory effects (e.g., airway hyperresponsiveness and inflammation, lung function, other ages and populations)	—	—	NO_2 ISA[2,3]
Reduced incidence of morbidity from exposure to SO_2	Respiratory hospital admissions (age > 65)	—	—	SO_2 ISA[1]
	Asthma emergency department visits (all ages)	—	—	SO_2 ISA[1]
	Asthma exacerbation (asthmatics age 4–12)	—	—	SO_2 ISA[1]
	Acute respiratory symptoms (age 7–14)	—	—	SO_2 ISA[1]
	Premature mortality	—	—	SO_2 ISA[1,2,3]
	Other respiratory effects (e.g., airway hyperresponsiveness and inflammation, lung function, other ages and populations)	—	—	SO_2 ISA[1,2]
Reduced incidence of morbidity from exposure to CO	Cardiovascular effects	—	—	CO ISA [1,2]
	Respiratory effects	—	—	CO ISA [1,2,3]
	Central nervous system effects	—	—	CO ISA [1,2,3]
	Premature mortality	—	—	CO ISA [1,2,3]
Reduced incidence of morbidity from exposure to methylmercury	Neurologic effects—IQ loss	—	—	IRIS; NRC, 2000[1]
	Other neurologic effects (e.g., developmental delays, memory, behavior)	—	—	IRIS; NRC, 2000[2]
	Cardiovascular effects	—	—	IRIS; NRC, 2000[2,3]
	Genotoxic, immunologic, and other toxic effects	—	—	IRIS; NRC, 2000[2,3]
Improved Environment				
Reduced visibility impairment	Visibility in Class 1 areas	—	—	PM ISA[1]
	Visibility in residential areas	—	—	PM ISA[1]
Reduced effects on materials	Household soiling	—	—	PM ISA[1,2]
	Materials damage (e.g., corrosion, increased wear)	—	—	PM ISA[2]
Reduced effects from PM deposition (metals and organics)	Effects on Individual organisms and ecosystems	—	—	PM ISA[2]
Reduced vegetation and ecosystem effects from exposure to ozone	Visible foliar injury on vegetation	—	—	Ozone ISA[1]
	Reduced vegetation growth and reproduction	—	—	Ozone ISA[1]
	Yield and quality of commercial forest products and crops	—	—	Ozone ISA[1]
	Damage to urban ornamental plants	—	—	Ozone ISA[2]
	Carbon sequestration in terrestrial ecosystems	—	—	Ozone ISA[1]
	Recreational demand associated with forest aesthetics	—	—	Ozone ISA[2]
	Other non-use effects			Ozone ISA[2]

Category	Effect	Effect Quantified	Effect Monetized	More Information
	Ecosystem functions (e.g., water cycling, biogeochemical cycles, net primary productivity, leaf-gas exchange, community composition)	—	—	Ozone ISA[2]
Reduced effects from acid deposition	Recreational fishing	—	—	NO_x SO_x ISA[1]
	Tree mortality and decline	—	—	NO_x SO_x ISA[2]
	Commercial fishing and forestry effects	—	—	NO_x SO_x ISA[2]
	Recreational demand in terrestrial and aquatic ecosystems	—	—	NO_x SO_x ISA[2]
	Other non-use effects			NO_x SO_x ISA[2]
	Ecosystem functions (e.g., biogeochemical cycles)	—	—	NO_x SO_x ISA[2]
Reduced effects from nutrient enrichment	Species composition and biodiversity in terrestrial and estuarine ecosystems	—	—	NO_x SO_x ISA[2]
	Coastal eutrophication	—	—	NO_x SO_x ISA[2]
	Recreational demand in terrestrial and estuarine ecosystems	—	—	NO_x SO_x ISA[2]
	Other non-use effects			NO_x SO_x ISA[2]
	Ecosystem functions (e.g., biogeochemical cycles, fire regulation)	—	—	NO_x SO_x ISA[2]
Reduced vegetation effects from ambient exposure to SO_2 and NO_x	Injury to vegetation from SO_2 exposure	—	—	NO_x SO_x ISA[2]
	Injury to vegetation from NO_x exposure	—	—	NO_x SO_x ISA[2]
Reduced ecosystem effects from exposure to methylmercury	Effects on fish, birds, and mammals (e.g., reproductive effects)	—	—	Mercury Study RTC[2]
	Commercial, subsistence and recreational fishing	—	—	Mercury Study RTC[1]

[1] We assess these co-benefits qualitatively due to data and resource limitations.

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

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

4.7.1 Hazardous Air Pollutant Impacts

Due to methodology and resource limitations, we were unable to estimate the impacts associated with changes in emissions of the hazardous air pollutants in this analysis. EPA's SAB-HES concluded that "the challenges for assessing progress in health improvement as a result of reductions in emissions of HAPs are daunting...due to a lack of exposure-response functions, uncertainties in emissions inventories and background levels, the difficulty of extrapolating risk estimates to low doses and the challenges of tracking health progress for diseases, such as cancer, that have long latency periods" (EPA-SAB 2008b). In 2009, the EPA convened a workshop to address the inherent complexities, limitations, and uncertainties in current methods to quantify the benefits of reducing HAP. Recommendations from this workshop included identifying research priorities, focusing on susceptible and vulnerable populations, and improving dose-response relationships (Gwinn et al. 2011).

4.7.1.1 Mercury

Mercury (Hg) in the environment is transformed into a more toxic form, methylmercury (MeHg). Because Hg is a persistent pollutant, MeHg accumulates in the food chain, especially the tissue of fish. When people consume these fish, they consume MeHg. In 2000, the NAS Study was issued which provides a thorough review of the effects of MeHg on human health (NRC 2000).[35] Many of the peer-reviewed articles cited in this section are publications originally cited in the Mercury Study.[36] In addition, the EPA has conducted literature searches to obtain other related and more recent publications to complement the material summarized by the NRC in 2000.

In its review of the literature, the NAS found neurodevelopmental effects to be the most sensitive and best documented endpoints and appropriate for establishing a reference dose (RfD) (NRC 2000); in particular NAS supported the use of results from neurobehavioral or neuropsychological tests. The NAS report noted that studies on animals reported sensory effects as well as effects on brain development and memory functions and supported the conclusions based on epidemiology studies. The NAS noted that their recommended endpoints for a RfD are associated with the ability of children to learn and to succeed in school. They concluded the following: "The population at highest risk is the children of women who consumed large amounts of fish and seafood during pregnancy. The committee concludes that the risk to that population is likely to be sufficient to result in an increase in the number of children who have to struggle to keep up in school."

The NAS summarized data on cardiovascular effects available up to 2000. Based on these and other studies, the NRC concluded that "Although the data base is not as extensive for cardiovascular effects as it is for other end points (i.e., neurologic effects), the cardiovascular system appears to be a target for MeHg toxicity in humans and animals." The NRC also stated that "additional studies are needed to better characterize the effect of methylmercury exposure on blood pressure and cardiovascular function at various stages of life."

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[35] National Research Council (NRC). 2000. *Toxicological Effects of Methylmercury*. Washington, DC: National Academies Press.

[36] U.S. Environmental Protection Agency (U.S. EPA). 1997. *Mercury Study Report to Congress*, EPA–HQ–OAR–2009–0234–3054. December. Available at http://www.epa.gov/hg/report.htm.

Additional cardiovascular studies have been published since 2000. The EPA did not develop a quantitative dose-response assessment for cardiovascular effects associated with MeHg exposures, as there is no consensus among scientists on the dose-response functions for these effects. In addition, there is inconsistency among available studies as to the association between MeHg exposure and various cardiovascular system effects. The pharmacokinetics of some of the exposure measures (such as toenail Hg levels) are not well understood. The studies have not yet received the review and scrutiny of the more well-established neurotoxicity data base.

The Mercury Study noted that MeHg is not a potent mutagen but is capable of causing chromosomal damage in a number of experimental systems. The NAS concluded that evidence that human exposure to MeHg caused genetic damage is inconclusive; they note that some earlier studies showing chromosomal damage in lymphocytes may not have controlled sufficiently for potential confounders. One study of adults living in the Tapajós River region in Brazil (Amorim et al. 2000) reported a direct relationship between MeHg concentration in hair and DNA damage in lymphocytes, as well as effects on chromosomes.[37] Long-term MeHg exposures in this population were believed to occur through consumption of fish, suggesting that genotoxic effects (largely chromosomal aberrations) may result from dietary and chronic MeHg exposures similar to and above those seen in the Faroes and Seychelles populations.

Although exposure to some forms of Hg can result in a decrease in immune activity or an autoimmune response (ATSDR 1999), evidence for immunotoxic effects of MeHg is limited (NRC 2000).[38] Based on limited human and animal data, MeHg is classified as a "possible" human carcinogen by the International Agency for Research on Cancer (IARC 1994)[39] and in

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[37] Amorim, M.I.M., D. Mergler, M.O. Bahia, H. Dubeau, D. Miranda, J. Lebel, R.R. Burbano, and M. Lucotte. 2000. Cytogenetic damage related to low levels of methyl mercury contamination in the Brazilian Amazon. An. Acad. Bras. Ciênc. 72(4): 497-507.
[38] Agency for Toxic Substances and Disease Registry (ATSDR). 1999. Toxicological Profile for Mercury. U.S. Department of Health and Human Services, Public Health Service, Atlanta, GA.
[39] International Agency for Research on Cancer (IARC). 1994. IARC Monographs on the Evaluation of Carcinogenic Risks to Humans and their Supplements: Beryllium, Cadmium, Mercury, and Exposures in the Glass Manufacturing Industry. Vol. 58. Jalili, H.A., and A.H. Abbasi. 1961. Poisoning by ethyl mercury toluene sulphonanilide. Br. J. Indust. Med. 18(Oct.):303-308 (as cited in NRC, 2000).

IRIS (U.S. EPA 2002).[40] The existing evidence supporting the possibility of carcinogenic effects in humans from low-dose chronic exposures is tenuous. Multiple human epidemiological studies have found no significant association between Hg exposure and overall cancer incidence, although a few studies have shown an association between Hg exposure and specific types of cancer incidence (e.g., acute leukemia and liver cancer) (NRC 2000).

There is also some evidence of reproductive and renal toxicity in humans from MeHg exposure. However, overall, human data regarding reproductive, renal, and hematological toxicity from MeHg are very limited and are based on either studies of the two high-dose poisoning episodes in Iraq and Japan or animal data, rather than epidemiological studies of chronic exposures at the levels of interest in this analysis.

4.7.1.2 Hydrogen Chloride

Hydrogen chloride (HCl) is a corrosive gas that can cause irritation of the mucous membranes of the nose, throat, and respiratory tract. Brief exposure to 35 ppm causes throat irritation, and levels of 50 to 100 ppm are barely tolerable for 1 hour.[41] Concentrations in typical human exposure environments are much lower than these levels and rarely exceed the reference concentration.[42] The greatest impact is on the upper respiratory tract; exposure to high concentrations can rapidly lead to swelling and spasm of the throat and suffocation. Most seriously exposed persons have immediate onset of rapid breathing, blue coloring of the skin, and narrowing of the bronchioles. Exposure to HCl can lead to Reactive Airways Dysfunction Syndrome (RADS), a chemically, or irritant-induced type of asthma. Children may be more vulnerable to corrosive agents than adults because of the relatively smaller diameter of their airways. Children may also be more vulnerable to gas exposure because of increased minute

[40] U.S. Environmental Protection Agency (EPA). 2002. Integrated Risk Information System (IRIS) on Methylmercury. National Center for Environmental Assessment. Office of Research and Development. Available at http://www.epa.gov/iris/subst/0073.htm.

[41] Agency for Toxic Substances and Disease Registry (ATSDR). Medical Management Guidelines for Hydrogen Chloride. Atlanta, GA: U.S. Department of Health and Human Services. Available at http://www.atsdr.cdc.gov/mmg/mmg.asp?id=758&tid=147#bookmark02.

[42] Table of Prioritized Chronic Dose-Response Values: http://www2.epa.gov/sites/production/files/2014-05/documents/table1.pdf

ventilation per kg and failure to evacuate an area promptly when exposed. Hydrogen chloride has not been classified for carcinogenic effects.[43]

4.7.2 NO_2 Health Co-Benefits

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

4.7.3 SO_2 Health Co-Benefits

In addition to being a precursor to $PM_{2.5}$, SO_2 emissions are also linked to a variety of adverse health effects associated with direct exposure. We were unable to estimate the health co-benefits associated with reduced SO_2 in this analysis. Therefore, this analysis only quantifies and monetizes the $PM_{2.5}$ co-benefits associated with the reductions in SO_2 emissions.

Following an extensive evaluation of health evidence from epidemiologic and laboratory studies, the *Integrated Science Assessment for Oxides of Sulfur —Health Criteria* (SO_2 ISA) concluded that there is a causal relationship between respiratory health effects and short-term

[43] U.S. Environmental Protection Agency (U.S. EPA). 1995. "Integrated Risk Information System File of Hydrogen Chloride." Washington, DC: Research and Development, National Center for Environmental Assessment. This material is available at http://www.epa.gov/iris/subst/0396.htm.

exposure to SO_2 (U.S. EPA 2017). The immediate effect of SO_2 on the respiratory system in humans is bronchoconstriction. Asthmatics are more sensitive to the effects of SO_2 likely resulting from preexisting inflammation associated with this disease. A clear concentration-response relationship has been demonstrated in laboratory studies following exposures to SO_2 at concentrations between 20 and 100 ppb, both in terms of increasing severity of effect and percentage of asthmatics adversely affected. Based on our review of this information, we identified three short-term morbidity endpoints that the SO_2 ISA identified as a "causal relationship": asthma exacerbation, respiratory-related emergency department visits, and respiratory-related hospitalizations. The differing evidence and associated strength of the evidence for these different effects is described in detail in the SO_2 ISA. The SO_2 ISA also concluded that the relationship between short-term SO_2 exposure and premature mortality was "suggestive of a causal relationship" because it is difficult to attribute the mortality risk effects to SO_2 alone. Although the SO_2 ISA stated that studies are generally consistent in reporting a relationship between SO_2 exposure and mortality, there was a lack of robustness of the observed associations to adjustment for other pollutants. We did not quantify these co-benefits due to data constraints.

4.7.4 NO_2 and SO_2 Welfare Co-Benefits

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

Deposition of nitrogen is also associated with aquatic and terrestrial nutrient enrichment. In estuarine waters, excess nutrient enrichment can lead to eutrophication. Eutrophication of estuaries can disrupt an important source of food production, particularly fish and shellfish production, and a variety of cultural ecosystem services, including water-based recreational and aesthetic services. Terrestrial nutrient enrichment is associated with changes in the types and number of species and biodiversity in terrestrial systems. Excessive nitrogen deposition upsets the balance between native and nonnative plants, changing the ability of an area to support biodiversity. When the composition of species changes, then fire frequency and intensity can also change, as nonnative grasses fuel more frequent and more intense wildfires (U.S. EPA 2008).

4.7.5 Ozone Welfare Co-Benefits

Exposure to ozone has been associated with a wide array of vegetation and ecosystem effects in the published literature (U.S. EPA 2013a). Sensitivity to ozone is highly variable across species, with over 65 plant species identified as "ozone-sensitive", many of which occur in state and national parks and forests. These effects include those that damage or impair the intended use of the plant or ecosystem. Such effects can include reduced growth and/or biomass production in sensitive plant species, including forest trees, reduced yield and quality of crops, visible foliar injury, species composition shift, and changes in ecosystems and associated ecosystem services.

4.7.6 Visibility Impairment Co-Benefits

Reductions in emissions of NO2 and SO2 will improve the level of visibility throughout the United States because these gases (and the particles of nitrate and sulfate formed from these gases) impair visibility by scattering and absorbing light (U.S. EPA 2009). Visibility is also referred to as visual air quality (VAQ), and it directly affects people's enjoyment of a variety of daily activities (U.S. EPA 2009). Good visibility increases quality of life where individuals live and work, and where they travel for recreational activities, including sites of unique public value, such as the Great Smoky Mountains National Park (U.S. EPA 2009).

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 2009). Fine particles with significant light-extinction efficiencies include sulfates, nitrates, organic carbon, elemental carbon, and soil (Sisler 1996). Visibility has direct significance to people's enjoyment of daily activities and their overall sense of wellbeing. Good visibility increases the quality of life where individuals live and work, and where they engage in recreational activities. Particulate sulfate is the dominant source of regional haze in the eastern U.S. and particulate nitrate is an important contributor to light extinction in California and the upper Midwestern U.S., particularly during winter (U.S. EPA 2009). Previous analyses show that visibility co-benefits can be a significant welfare benefit category (U.S. EPA 2011d). In this analysis, we did not estimate visibility related benefits or whether the emission reductions associated with the final emission guidelines would be likely to have a significant impact on visibility in urban areas or mandatory Class I areas, i.e., federal wilderness areas and national parks.

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CHAPTER 5: ECONOMIC AND EMPLOYMENT IMPACTS

5.1 Economic Impacts

5.1.1 Market Impacts

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

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

To estimate the costs, benefits, and impacts of implementing the final guidelines, the EPA modeled an illustrative policy scenario. Chapter 1 and Chapter 3 describe the illustrative policy scenario. This chapter provides a quantitative assessment of the energy price impacts for the illustrative policy scenario and a qualitative assessment of the factors that will in part determine the timing and magnitude of potential effects in other markets. Table 5-1 summarizes projected changes in energy prices and fuel use resulting from the illustrative policy scenario.

Table 5-1 Summary of Certain Energy Market Impacts (Percent Change)

	2025	2030	2035
Retail electricity prices	0.1%	0.1%	0.0%
Average price of coal delivered to the power sector	0.1%	0.0%	-0.1%
Coal production for power sector use	-1.1%	-1.0%	-1.0%
Price of natural gas delivered to power sector	0.0%	-0.1%	-0.6%
Price of average Henry Hub (spot)	0.0%	0.0%	-0.6%
Natural gas use for electricity generation	-0.4%	-0.3%	0.0%

Note: Positive values indicate increases relative to the baseline.

To provide some historical context to Table 5-1, we present below recent trends observed over the last decade (2008 to 2018) for the energy market impacts listed:[1]

- The annual percent change in electricity price over this period has been from -1.3 percent to 2.0 percent, and averaged 0.8 percent.
- The percent change to the annual price of coal for electricity generation has ranged from -6 percent to 6.8 percent over the past decade, and averaged 0.1 percent.
- The percent change to annual coal use for electricity plants has ranged from -17 percent to 4.3 percent over the past decade, and averaged -5.9 percent.
- The percent change to the average cost of natural gas for electricity generation has ranged from -6 percent to 6.8 percent over the past decade, and averaged 0.1 percent.
- The percent change to annual natural gas use for electricity plants has ranged from -10.5 percent to 17.2 percent over the past decade, and averaged 2.8 percent.

Overall, these projected changes are relatively small in the context of recent historical changes.

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

[1] Source: EIA Electricity Data Browser, all data is nominal dollars, available at https://www.eia.gov/electricity/data/browser/. For natural gas use and coal production, receipts of both fuels for electricity generators are used as a close proxy.

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

Changes in supply or demand for electricity, natural gas, and coal can impact markets for goods and services produced by sectors that use these energy inputs in the production process or that supply those sectors. Changes in cost of production may result in changes in price and/or quantity produced by these sectors and these market changes may affect the profitability of firms and the economic welfare of their consumers and owners. Any potential changes in the operation of the electric power sector due to the final action may also have an effect on upstream industries that supply goods and services to the sector. For example, losses for owners and workers at firms that supply new generation technologies and gains for firms that supply the parts and labor necessary to improve heat rates at existing coal steam generators. The magnitude and direction of these potential effects outside the electricity sector and related fuel markets are not analyzed in this RIA.

One potential approach to evaluating whether there are important secondary market impacts is to use an economy-wide model. Economy-wide models - and, more specifically, computable general equilibrium (CGE) models - are analytical tools that can be used to evaluate the impacts of a regulatory action beyond the directly-regulated sector. CGE models provide aggregated representations of the entire economy in equilibrium in the baseline and under a regulatory or policy scenario. 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 distortions, such as taxes. They can provide information on changes outside of the directly-regulated sector attributable to a regulation. For example, CGE studies of air pollution regulations for the power sector have found that the social costs and benefits may be greater or lower than partial equilibrium estimates when these secondary market impacts are taken into account, and that the direction of the estimates may depend on the form of the regulation (e.g. Goulder et al. 1999, Williams 2002, Goulder et al. 2016).

In March 2015, the EPA established a Science Advisory Board (SAB) panel to consider the technical merits and challenges of using economy-wide models to evaluate costs, benefits, and economic impacts in regulatory development. In September 2017, the SAB issued its final report, which provided recommendations on how the EPA can use CGE models to offer a more comprehensive assessment of the benefits, costs, and economic impacts of regulatory actions.[2] The report noted that the case for using CGE models to evaluate a regulation's effects is strongest when the costs of abatement are expected to be large in magnitude and the sector has strong linkages to the rest of the economy, although the CGE models may also be useful to evaluate impacts of smaller regulations in some situations. The report also noted that the extent to which CGE models add value to the analysis depends on data availability, in that data limitations are a significant obstacle to achieving the granularity needed to adequately represent a regulation in the model to estimate its effects. In response to these and other SAB recommendations, the EPA is in the process of building capacity to allow for the use of CGE models in the analysis of future regulatory actions when warranted, developing guidance for analysts on when CGE analysis is most likely to add value, and pursuing research priorities highlighted by the SAB in its report.

5.1.2 Distributional Impacts

Any potential costs or benefits of this final action are not expected to be experienced uniformly across the population, and may not accrue to the same individuals or communities. OMB recommends including a description of distributional effects, as part of a regulatory analysis, "so that decision makers can properly consider them along with the effects on economic efficiency [i.e., net benefits]. Executive Order 12866 authorizes this approach." (U.S. Office of Management and Budget 2003). Understanding the distribution of the compliance costs and benefits can aid in understanding community-level impacts associated with this final action.[3] This section discusses the general expectations regarding how compliance costs, and health benefits might be distributed across the population, relying on a review of recent literature. For

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[2] Science Advisory Board, USEPA. 2017. SAB Advice on the Use of Economy-Wide Models in Evaluating the Social Costs, Benefits, and Economic Impacts of Air Regulations. https://yosemite.epa.gov/sab/SABPRODUCT.NSF/0/4B3BAF6C9EA6F503852581AA0057D565/$File/EPA-SAB-17-012.pdf

[3] Executive Order 12898, *Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations,* directs agencies to address impacts on minority and low-income populations, particularly those that may be considered disproportionate. The EPA developed guidance, both in its *Guidelines for Preparing Economic Analyses* (U.S. EPA 2010) and *Technical Guidance for Assessing Environmental Justice in Regulatory Analyses* (U.S. EPA 2016) to provide recommendations for how to consider distributional impacts of rules on vulnerable populations.

example, Fullerton (2011) discussed six potential distributional impacts related to environmental policy using a carbon permit system: impacts on consumers (e.g. higher energy prices); impacts on producers or factors (e.g., lower returns to capital); scarcity rents (e.g. value of right to pollute); benefits associated with pollution reduction; and transition costs (e.g., from changes in employment or capital mix). The EPA did not conduct a quantitative assessment of these distributional impacts for this final action, but the qualitative discussion in this section provides a general overview of the types of impacts that could result from this action. We begin each sub-section below with a general discussion of the incidence from the literature, followed by a brief discussion of the distributional consequences we might expect from this final action.

5.1.2.1 Distributional Aspects of Compliance Costs

The compliance costs associated with a regulatory action can impact households by raising the prices of goods and services; the extent of the price increase depends on if and how producers pass-through those costs to consumers. Expenditures on energy are usually a larger share of low-income household income than that of other households, and this share falls as income increases. Therefore, policies that increase energy prices have been found to be regressive, placing a greater burden on lower income households (e.g., Burtraw et al., 2009; Hassett et al., 2009; Williams et al. 2015). However, compliance costs will not be solely passed on in the form of higher energy prices, but also through lower labor earnings and returns to capital in the sector. Changes in employment associated with lower labor earnings can have distributional consequences depending on several factors (Section 5.2 discusses employment effects further). Capital income tends to make up a greater proportion of overall income for high income households. As result, the costs passed through to households via lower returns to capital tend to be progressive, placing a greater share of the burden on higher income households in these instances (Rausch et al., 2011; Fullerton et al., 2011). On net, capital owners in the power sector may even see a higher return to capital as output is restricted or the economic position of certain competitors is improved relative to their competitors (Maloney and McCormick, 1982; Buchanan and Tullock, 1975) due to a regulation. In these circumstances the incidence through capital may be regressive.

The ultimate distributional outcome will depend on how changes in electricity and other fuel and input prices and lower returns to labor and capital propagate through the economy and interact with existing government transfer programs.[4] Some studies using an economy-wide framework find that the overall distribution of compliance costs is progressive due to the changes in capital payments and the expectation that existing government transfer indexed to inflation will offset the burden to lower income households (Fullerton et al., 2011; Blonz et al., 2012).[5] However, others have found the distribution of compliance costs to be regressive due to a dominating effect of changes in energy prices to consumers (Fullerton 2011; Burtraw, et. al., 2009; Williams, et al., 2015). There may also be significant heterogeneity in the costs borne by individuals within income deciles (Rausch et al., 2011; Cronin et al., 2019). Different classifications of households, for example based on lifetime income rather than contemporaneous annual income, may provide notably different results (Fullerton and Metcalf, 2002; Fullerton et al., 2011).

Furthermore, there may be important regional differences in the incidence of regulations. There are differences in the composition of goods consumed, regional production methods (e.g., the composition of the generation fleet), the stringency of a rule, as well as the location of affected labor and capital ownership (the latter of which may be foreign-owned) (e.g. Caron et. al 2018; Hassett et al. 2009).

Given the complexity of the problem, estimating all of the distributional impacts of compliance costs may require an economy-wide analysis (Rausch and Mowers, 2014), which as discussed above can be challenging. While such an analysis was not conducted for this final action, we can attempt to understand the distributional impacts of a policy by examining its various components in their relevant partial equilibrium settings (Fullerton 2011). For example, using partial-equilibrium modeling, studies that have focused on the incidence of electricity sector regulations have generally found that consumers bear more of the compliance cost of a regulation than producers because demand for electricity is relatively inelastic and, in cost-of-service regions, increased production costs may be passed through electricity prices (e.g.

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[4] Some of these programs target low-income households. For example, the Low Income Home Energy Assistance Program (LIHEAP): "assists eligible households with heating and cooling energy costs, bill payments, weatherization and energy-related home repairs" and may mitigate increases in electricity prices on low-income households as a result of this final rule. See: https://www.benefits.gov/benefit/623.

[5] The incidence of government transfer payments (e.g., Social Security) is generally progressive because these payments represent a significant source of income for lower income deciles and only a small source for high income deciles. Government transfer programs are often, implicitly or explicitly, indexed to inflation. For example, Social Security payments and veterans' benefits are adjusted every year to account for changes in prices (i.e., inflation).

Burtraw and Palmer 2008). Even in these studies, the details of the form of the regulation matters.

While the aforementioned components are important for understanding the ultimate distribution of compliance costs in this context, it is not clear the degree to which the specific results may be transferred to the current context. For example, much of the previous literature has focused on the distributional impacts of first best policies, such as an economy-wide emissions fee or permit trading program. Subsequent research focusing on second best policy designs such as economy-wide clean or renewable energy standards or power sector only permit trading programs have found the net distribution of costs to be relatively regressive even when accounting for the impacts on consumers and factors of production, as well as the indexing of transfer payments to inflation (Rausch and Mowers, 2014). This suggests that moving from a more flexible to a less flexible regulatory design with EGU-specific requirements, will in and of itself, affect the distribution of regulatory burden. Ultimately, the distribution of compliance costs may be regressive or progressive, depending on the factors indicated above as well as other implementation choices.

5.1.2.2 Distributional Aspects of the Health Benefits

Executive Order 12898, *Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations,* directs agencies to address impacts on minority populations, low-income populations and indigenous peoples, particularly those that may be considered disproportionate. A distributional, or Environmental Justice, analysis may characterize the change in air pollution exposure and risk among minority populations, low-income populations and indigenous peoples (see U.S. EPA 2015b, 2016). Often the baseline incidence of health outcomes is greater among minority populations, low-income populations and indigenous peoples due to a variety of factors, including a greater number of pollution sources located where low-income and minority populations live, work and play (Bullard, et al. 2007; United Church of Christ 1987); greater susceptibility to a given exposure due to physiology or other triggers (Akinbami et al. 2012); and pre-existing conditions (Schwartz et al. 2011). For these reasons, an EJ analysis can characterize the change in the estimated distribution of risk occurring as a result of implementing the policy.

This final action will affect the level and distribution of air pollutants in the atmosphere. When evaluating policies prescribing specific emission control measures, we can more confidently characterize the change in the distribution of pollutant concentrations and risk (US EPA 2011). This analysis, by contrast, simulates the expected change in air quality from an illustrative policy scenario (Figure 4-3). While this rule prescribes the development of CO_2 emissions standards at coal-fired EGUs, for reasons discussed in Chapter 1 and elsewhere in this RIA, the air emission changes at individual units from the final rule may differ than modeled in the illustrative policy scenario, and therefore the level and location of changes in air pollutant concentrations may differ as well. Furthermore, the illustrative policy scenario was not constructed to consider possible local conditions that may influence eventual emission outcomes. For these reasons and consistent with analysis presented elsewhere in this RIA (e.g. Section 3.7.8), we do not quantitatively assess the change in air pollution concentrations or risk among minority populations, low-income populations and indigenous peoples from the illustrative policy scenario as doing so would suggest greater certainty in the regional impacts of this final rule than is warranted. Furthermore, we do not evaluate the effect of potential non-air environmental impacts nor market effects such as changes in electricity prices on EJ communities. As a result, we cannot conclude whether this rule will have disproportionate impacts on EJ communities. However, in light of the results of the simulated air quality changes depicted in Chapter 4, it is reasonable to infer that U.S. populations will, on balance, experience a small but meaningful decrease in annual mean $PM_{2.5}$ and summer season ozone concentrations (Figure 4-3). Furthermore, as noted in Chapter 3, increases in emissions at individual units indicated in the modeling scenario may in practice be mitigated by other economic and regulatory factors.

5.1.3 Impacts on Small Entities

Emission guidelines established under CAA section 111(d) do not impose any requirements on regulated entities and, thus, will not have direct impacts on these entities. After emission guidelines are promulgated, states establish emission standards on existing sources, and it is those requirements that could potentially impact small entities. As a result, this action will not have a significant economic impact on a substantial number of small entities under the RFA.

Our analysis here is consistent with the analysis of the analogous situation arising when the EPA establishes NAAQS, which do not impose any requirements on regulated entities. As here, any impact of a NAAQS on small entities would only arise when states take subsequent action to maintain and/or achieve the NAAQS through their state implementation plans. See American Trucking Assoc. v. EPA, 175 F.3d 1029, 1043-45 (D.C. Cir. 1999) (NAAQS do not have significant impacts upon small entities because NAAQS themselves impose no regulations upon small entities).

5.2 Employment Impacts

Environmental regulation may affect groups of workers differently, as changes in abatement and other compliance activities cause labor and other resources to shift. An employment impact analysis describes the characteristics of groups of workers potentially affected by a regulation, as well as labor market conditions in affected occupations, industries, and geographic areas. Standard benefit-cost analyses have not typically included a separate analysis of regulation-induced employment impacts.[6] In this section we discuss the potential employment impacts of the ACE rule.

Employment impacts of environmental regulations are composed of a mix of potential declines and gains in different sectors of the economy over time. Impacts on employment can vary according to labor market conditions and may differ across occupations, industries, and regions. Isolating employment impacts of regulation is a challenge, as they are difficult to disentangle from employment impacts caused by a wide variety of ongoing concurrent economic changes.

Environmental regulation "typically affects the distribution of employment among industries rather than the general employment level" (Arrow *et. al.* 1996). Even if they are mitigated by long-run market adjustments to full employment, many regulatory actions have transitional effects in the short run (U.S. Office of Management and Budget 2015). These movements of workers in and out of jobs in response to environmental regulation are potentially important distributional impacts of interest to policy makers. Of particular concern are

[6] Labor expenses do, however, contribute toward total costs in EPA's standard benefit-cost analyses. See Section 3.6 of this RIA, for a discussion of labor expenses required for monitoring, reporting, and record keeping.

transitional job losses experienced by workers operating in declining industries, exhibiting low migration rates, or living in communities or regions where unemployment rates are high.

If the U.S. economy is at full employment, as current economic conditions indicate is likely, even a large-scale environmental regulation is unlikely to have a noticeable impact on aggregate net employment.[7] Instead, labor in affected sectors would primarily be reallocated from one productive use to another (e.g., from producing electricity or steel to producing high efficiency equipment), and net national employment effects from environmental regulation would be small and transitory (e.g., as workers move from one job to another). There may still be employment effects, negative and positive, for groups of affected workers, even if the overall net effect is small or zero. Some workers may retrain or relocate in anticipation of new requirements or require time to search for new jobs, while shortages in some sectors or regions could bid up wages to attract workers. These adjustment costs can lead to local labor disruptions. Although the net change in the national workforce is expected to be small under conditions of full employment, localized reductions in employment may adversely impact individuals and communities just as localized increases may have positive impacts.

An environmental regulation affecting the power sector is expected to have a variety of transitional employment impacts, including reduced employment at retiring coal-fired facilities, as well as increased employment for the manufacture, installation, and operation of pollution control equipment and construction of new generation sources to replace retiring units (Schmalensee and Stavins, 2011). For the ACE rule, the EPA expects potential for changes in the amount of labor needed in different parts of the utility power sector.[8] These employment impacts, both negative and positive, are likely to be small, particularly when considered in light of larger power sector trends as discussed in Chapter 2.

Illustrative compliance cost projections for the electric power sector and for the fuel production sector (coal and natural gas) are described in more detail in Chapter 3 of this RIA, and may include effects attributable to heat rate improvements (HRIs), changes in construction

[7] Full employment is a conceptual target for the economy where everyone who wants to work and is available to do so at prevailing wages is actively employed. The unemployment rate at full employment is not zero.
[8] The employment analysis in this RIA is part of EPA's ongoing effort to "conduct continuing evaluations of potential loss or shifts of employment which may result from the administration or enforcement of [the Act]" pursuant to CAA section 321(a).

of new EGUs, generation shifts, and changes in fuel production and use. Considering first the electric power sector, transitional employment impacts may occur in the short-run, where we project a small increase in construction of new capacity, and during plant installation or modification of equipment and buildings, and training of new processes. Over a longer time frame, transitional employment impacts are replaced by ongoing operation and maintenance labor requirements.

An important impact of these final rules is the implementation of measures that improve heat rate at existing coal-fired generators which are associated with two main categories of employment. In the short-run, there will be construction-related work; e.g., engineering, design, and installation of boilermakers and associated materials and equipment. In the long-run, there may be operation and maintenance employment to ensure the HRI is maintained in future years. (Staudt 2014). Likewise, there are similar categories of employment for the other shifts caused by the final rules such as shifts in the construction and operation of new EGUs, shifts in generation, and for the fuel production sectors - coal and natural gas - employment impacts may occur with changes in projected coal extraction and natural gas extraction.

Given the range of approaches to HRI that may be used to meet the requirements of the final rules, and the flexibility for States to determine these requirements, it is challenging to quantify the associated employment impacts. For this regulatory action, based on the illustrative policy scenario modeled in IPM which are described in more detail in Chapter 3 of this RIA, the EPA expects there may be potential for changes in the amount of labor needed in different parts of the power sector.

The U.S. Department of Energy, in cooperation with BLS, gathered and published detailed information on energy employment (U.S. DOE (2017a & 2017b)).[9] Detailed information on characteristics of workers, by job tasks, is available for the electricity sector and related

[9] Main website: https://energy.gov/downloads/2017-us-energy-and-employment-report, with links to the 2017 report (https://energy.gov/sites/prod/files/2017/01/f34/2017%20US%20Energy%20and%20Jobs%20Report_0.pdf) and associated state charts (https://energy.gov/sites/prod/files/2017/01/f34/2017%20US%20Energy%20and%20Jobs%20Report%20State%20Charts%202_0.pdf). U.S. DOE produced the U.S. Energy and Employment Report in 2016 and 2017, and did not produce a report in 2018. In 2018, Energy Futures Initiative (EFI) with support from the National Association of State Energy Officials (NASEO) drafted a report on employment in the energy sector, available here: https://www.usenergyjobs.org/.

sectors, and by state. To shed light on who will be affected by any potential employment changes associated with the final rules, we review the characteristics of potentially affected workers.

For workers in coal-fired utilities, there are notable differences in the characteristics of average groups of workers relative to national workforce averages. At coal-fired utilities, there are more men than women in the workforce (63 percent versus 53 percent), and they are, on average, younger (13 percent are 55 and over, versus 22 percent nationally) (U.S. DOE 2017a). These characteristics for workers in natural gas electricity generation are similar, in that there are more men than women in the workforce (60 percent versus 53 percent), and they are, on average, younger (17 percent are 55 and over, versus 22 percent nationally) (U.S. DOE 2017a). For hydroelectric and nuclear generation, there are more men in the workforce (66 percent for traditional hydroelectric, 62 percent for nuclear), and they are as a group, younger (14 percent are 55 and over, in traditional hydroelectric generation, and 12 percent in nuclear). Finally, for renewables, there are more male than female workers in solar electric generation (67 percent), also in wind (68 percent male), and in bioenergy for electricity generation (66 percent male). These workforces are also, on average, younger: in solar generation 13 percent of workers are 55 and over, versus 22 percent nationally, in wind 14 percent are 55 and over, and for workers in bioenergy for electric generation; 11 percent are 55 and over. Electric utilities and their workforce are distributed widely across the country. This lessens concerns that they are regionally concentrated in a high unemployment location.

The demographic differences of employees in coal mining and natural gas fuels, relative to national workforce averages, are more notable than for electric utility workers. Men compose most of the coal mining workforce (76 percent versus national average 53 percent), and they are, on average, older, with 28 percent of the coal mining workforce age 55 and over, versus 22 percent nationally (U.S. DOE 2017a). Similarly, men compose most of the natural gas fuels workforce (76 percent), and they are, on average, older, with 24 percent of the natural gas fuels workforce age 55 and over (U.S. DOE 2017a). Coal mines are necessarily located on coal seams, and natural gas fuels are extracted from basins; these are not distributed evenly throughout the U.S. As such, coal and natural gas fuels workers may be more tied to local labor markets and economies in terms of available employment opportunities. This raises a concern discussed further below.

The location of energy generation and fuel extraction activities is an important issue for considering distributional effects. Department of Energy (2017a) observes: "But within this overall story of [energy employment] growth is also an uneven trajectory where some states experience new jobs and others grapple with decline. States such as California and Texas, which have abundant solar, wind, and fossil fuel resources, have shown dramatic employment gains, despite some losses linked to low fossil fuel prices. Coal-dependent states, such as West Virginia and Wyoming, have seen declines in employment since 2015." (U.S. DOE, 2017a). In addition to the main report, Department of Energy has published similarly detailed information on energy employment, by state (DOE 2017a, 2017b).

The extent to which workers in declining industries will be significantly affected by the final action, depends on such factors as the transferability of affected workers' skills with shifting labor demand in different sectors due to the action, the availability of local employment opportunities for affected workers in communities or industries with high unemployment, and the extent to which migration costs serve as barriers to job search. This latter factor is a bigger concern in areas with historically low migration rates.

On the other hand, dislocated workers operating in tight labor markets may have experienced relatively brief periods of transitional unemployment. Some job seekers may find new employment opportunities due to these final rules; for example, if their skill set qualified them for new jobs implementing HRIs.

Speaking more generally, localized reductions in employment may adversely affect individuals and communities, just as localized increases may have positive effects (U.S. EPA 2015a p. 6-5). If potentially dislocated workers are vulnerable, for example as those in Appalachia likely are, besides experiencing persistent job loss as already mentioned, earnings can be permanently lowered, and the wider community may be negatively affected. Community-wide effects can include effects on the local tax base, the provision and quality of local public goods, and changes in demand for local goods and services. Neighborhood effects, when people influence neighbors' behaviors, may be possible. As an example, consider the influence that social networks can have on job acquisition. Many job vacancies are filled by people who know an employee at the firm with the vacancy. This type of networking is weakened by high unemployment rates (Durlauf 2004).

The distributional effects of workforce disruptions may extend beyond impacts on employment. Sociological studies examine different effects than those that are typically examined in economic studies. Workers experiencing unemployment may also experience negative health impacts. The unemployed population is observed to be less healthy than those who are employed, and the differences in health across these groups can be significant (see, for example, Roelfs, et al. 2011) including different rates of substance abuse (Compton, et al. 2014). The literature describes difficulties in identifying the cause of poorer health for the unemployed population. Associations between unemployment and poorer health may be partially driven by the possibility that workers in poorer health may be more likely to become unemployed. Estimates of the magnitude of the association may be biased, in part, by factors not easily observed or addressed by researchers that contribute both to unemployment risk as well as poorer health (Jin 1995, Sullivan and von Wachtner 2009). Several recent papers have attempted to identify a causal relationship between unemployment and health. These papers examined the health effects of involuntary job loss by focusing on workers who have lost their jobs due to layoffs or other firm-level employment reductions. For example, Sullivan and von Wachtner (2009) found increased mortality rates among displaced workers in Pennsylvania; and in a study of displaced Austrian workers, Kuhn, et al. (2007) found that job loss negatively affected men’s mental health.

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CHAPTER 6: COMPARISON OF BENEFITS AND COSTS

6.1 Introduction

This chapter presents the estimates of the climate benefits, ancillary health co-benefits, compliance costs and net benefits associated with the ACE rule, as represented by the illustrative policy scenario, relative to the baseline. We evaluate the potential regulatory impacts of the illustrative policy scenario using the present value (PV) of costs, benefits, and net benefits, calculated for the years 2023-2037 from the perspective of 2016, using both a three percent and seven percent end-of-period discount rate. All benefit analysis, and most cost analysis, begins in the year 2025. The only cost analysis for a year prior to 2025 is that for monitoring, reporting, and recordkeeping (MR&R), as MR&R costs are estimated to begin in 2023. In addition, the Agency presents the assessment of costs, benefits, and net benefits for specific snapshot years, consistent with historic practice. In this RIA, the regulatory impacts are evaluated for the specific years of 2025, 2030, and 2035.

There are potential sources of benefits and costs that may result from this final rule that have not been quantified or monetized. Due to current data and modeling limitations, our estimates of the benefits from reducing CO_2 emissions do not include important impacts like ocean acidification or potential tipping points in natural or managed ecosystems. Unquantified benefits also include climate benefits from reducing emissions of non-CO_2 greenhouse gases and benefits from reducing exposure to SO_2, NO_X, and hazardous air pollutants (e.g., mercury), as well as ecosystem effects and visibility impairment. The compliance costs reported in this RIA are not social costs, although in this analysis we use compliance costs as a proxy for social costs. We do not account for changes in costs and benefits due to changes in economic welfare of suppliers to the electricity market, or to non-electricity consumers from those suppliers. Furthermore, costs due to interactions with pre-existing market distortions outside the electricity sector are omitted. Additional limitations of the analysis and sources of uncertainty are described throughout the RIA and summarized in the Executive Summary.

6.2 Methods

The EPA calculated the PV of costs, as well as the benefits and net benefits, for the years 2023 through 2037, using both a three percent and seven percent end-of-period discount rate from the perspective of 2016. This calculation of a PV requires an annual stream of costs for each year of the 2023-2037 timeframe. The EPA used IPM to estimate cost and emission changes for the projection years 2025, 2030, and 2035. The Agency believes that these specific years are each representative of several surrounding years, which enables the analysis of costs and benefits over the timeframe of 2025-2037. The year 2025 is an approximation for when the standards of performance under the final rule might be implemented, and the Agency estimates that monitoring, reporting, and recordkeeping (MR&R) costs may begin in 2023. Therefore, MR&R costs analysis is presented beginning in the year 2023, and full benefit cost analysis is presented beginning in the year 2025. The analytical timeframe concludes in 2037, as this is the last year that may be represented with the analysis conducted for the specific year of 2035.

Estimates of costs and emission changes in other years are determined from the mapping of projection years to the calendar years that they represent. In the IPM modeling for this RIA, the 2025 projection year represents 2025-2027, 2030 represents 2028-2032, and 2035 represents 2033-2037.[1] Consequently, the cost and emission estimates from IPM in each projection year are applied to the years which it represents.[2] Climate benefits estimates are based on these projection year emission estimates, and also account for year-specific interim domestic SC-CO_2 values.[3] Ancillary health co-benefits are based on projection year emission estimates, and also account for year-specific variables that influence the size and distribution of the benefits; these include population growth, income growth, and the baseline rate of death.[4] The EPA has estimated MR&R costs for 2023, and applies these costs only to 2023 in the PV analysis. MR&R costs for

[1] For more information regarding the mapping of projection years to calendar years, see Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model (2018), available at: https://www.epa.gov/airmarkets/clean-air-markets-power-sector-modeling

[2] MR&R costs estimates are not based on IPM. For information on MR&R costs, see Chapter 3.

[3] As the interim domestic SC-CO_2 value varies by year, the climate benefit estimates vary by year, even when different years are based on the same IPM projection year emission estimate.

[4] As these variables differ by year, the ancillary health co-benefit estimates vary by year, even when different years are based on the same IPM projection year emission estimate.

2025 are applied to 2024, and all subsequent MR&R costs are applied to the 2025-2037 timeframe in the same fashion as other cost estimates.

The EPA calculated the PV and equivalent annualized value (EAV) of costs, benefits, and net benefits over the 2023-2037 timeframe for the illustrative policy scenario under different methodologies for calculating benefits. The EAV represents a flow of constant annual values that, had they occurred in each year from 2023 to 2037, would yield an equivalent present value. The EAV represents the value of a typical cost or benefit for each year of the analysis, in contrast to the year-specific estimates presented elsewhere for the snapshot years of 2025, 2030, and 2035.

6.3 Results

6.3.1 Analysis of 2023-2037 for E.O. 13771, Reducing Regulation and Controlling Regulatory Costs

This final action is considered a regulatory action under E.O. 13771, Reducing Regulation and Controlling Regulatory Costs.

Table 6-1 presents the undiscounted compliance costs for the illustrative policy scenario, representing the ACE rule, relative to the baseline. As noted earlier, the avoided compliance cost estimates from each IPM model year are applied to the appropriate surrounding years.

Table 6-1 Compliance Costs for the Illustrative Policy Scenario, 2023-2037 (millions of 2016$)[a]

Year	Compliance Cost[b]
2023	28
2024	15
2025	290
2026	290
2027	290
2028	280
2029	280
2030	280
2031	280
2032	280
2033	25
2034	25
2035	25
2036	25
2037	25

[a] All estimates are rounded to two significant figures, so figures may not sum due to independent rounding.
[b] Compliance costs included compliance costs and MR&R costs.

The EPA calculated the PV of costs using both a three percent and seven percent discount rate. The EPA used an end-of-period discount rate for E.O. 13771 analysis. The estimates for the illustrative policy scenario are presented in Table 6-2 and are from the perspective of 2016. For purposes of E.O. 13771 accounting, the PV and EAV estimates assume an infinite timeframe (i.e., over ∞). This is different than elsewhere in this RIA, where PV and EAV estimates are for the timeframe of 2023 to 2037.

Under the illustrative policy scenario, the PV of the stream of costs is $4.5 billion when discounted at 3 percent, and $1.5 billion when discounted at 7 percent. These compliance cost estimates represent the regulatory costs related to the regulatory allowance under E.O. 13771. Table 6-2 also presents the EAV.

Table 6-2 Present Value and Equivalent Annualized Value of Compliance Costs for the Illustrative Policy Scenario, 3 and 7 Percent Discount Rates, 2023-2037 (millions of 2016$)

	3%	**7%**
Present Value (over ∞)	4,500	1,500
Equivalent Annualized Value (over ∞)	140	110

Notes: Compliance costs included compliance costs and MR&R costs. All estimates are rounded to two significant figures, so figures may not sum due to independent rounding.

6.3.2 Net Benefits Analysis

Net benefits analysis is presented in terms of PV and EAV from the perspective of 2016, calculated using both a three percent and seven percent end-of-period discount rate. In this section, the PV and EAV estimates represent the timeframe of 2023 to 2037, and do not assume an infinite time horizon as in section 6.3.1.

Table 6-4 presents the PV and EAV estimates of compliance costs, domestic climate benefits, ancillary health co-benefits, and net benefits for the illustrative policy scenario.

Table 6-3 Present Value and Equivalent Annualized Value of Compliance Costs, Domestic Climate Benefits, Ancillary Health Co-Benefits, and Net Benefits, Illustrative Policy Scenario, 3 and 7 Percent Discount Rates, 2023-2037 (millions of 2016$)

	Costs		Domestic Climate Benefits		Ancillary Health Co-Benefits		Net Benefits	
	3%	**7%**	**3%**	**7%**	**3%**	**7%**	**3%**	**7%**
2023	22	17	-	-	-	-	(22)	(17)
2024	12	8.4	-	-	-	-	(12)	(8.4)
2025	220	150	60	6.7	290 to 720	180 to 460	130 to 560	43 to 320
2026	210	140	59	6.5	290 to 710	170 to 440	140 to 560	44 to 310
2027	200	130	59	6.2	280 to 710	170 to 420	140 to 560	45 to 300
2028	190	110	53	5.5	320 to 790	180 to 450	190 to 650	72 to 340
2029	180	110	52	5.3	320 to 780	170 to 430	190 to 650	72 to 320
2030	180	100	52	5.1	320 to 780	170 to 410	190 to 650	71 to 310
2031	170	93	51	4.9	310 to 770	160 to 390	190 to 650	69 to 300
2032	170	87	50	4.8	310 to 770	150 to 370	200 to 650	69 to 290
2033	15	7.4	41	3.8	310 to 760	140 to 360	330 to 780	140 to 350
2034	14	6.9	40	3.6	310 to 750	140 to 340	330 to 780	130 to 340
2035	14	6.4	40	3.5	300 to 750	130 to 330	330 to 770	130 to 320
2036	13	6.0	39	3.4	300 to 740	130 to 310	330 to 770	120 to 310
2037	13	5.6	39	3.2	300 to 730	120 to 300	320 to 760	120 to 290
Present Value	**1,600**	**970**	**640**	**62**	**4,000 to 9,800**	**2,000 to 5,000**	**3,000 to 8,800**	**1,100 to 4,100**
Equivalent Annualized Value	**140**	**110**	**53**	**6.9**	**330 to 820**	**220 to 550**	**250 to 730**	**120 to 450**

Notes: All estimates are rounded to two significant figures, so figures may not sum due to independent rounding. Climate benefits reflect the value of domestic impacts from CO_2 emissions changes.

6.3.2.1 Targeted Pollutant

In the decision-making process it is useful to consider the change in benefits due to the targeted pollutant relative to the costs.[5] In Table 6-4 we offer one perspective on the costs and

[5] Regulating pollutants jointly can promote a more efficient outcome in pollution control management (Tietenberg, 1973). However, in practice regulations are promulgated sequentially and therefore, the benefit-cost analyses supporting those regulations are also performed sequentially. The potential for interaction between regulations suggests that their sequencing may affect the realized efficiency of their design and the estimated net benefits for each regulation. For this rulemaking, the EPA did not consider alternative regulatory approaches to jointly control CO_2, direct $PM_{2.5}$, SO_2, and NO_X emission from existing power plants. This leaves open the possibility that an option which jointly regulates CO_2, direct $PM_{2.5}$, SO_2, and NO_X emissions from power plants could have achieved these reductions more efficiently than through a single regulation targeting CO_2 emissions, conditional on statutory authority to promulgate such a regulation.

benefits of this rule by presenting a comparison of the benefit impact associated with the targeted pollutant – CO_2 – with the compliance cost impact.[6] It is important to recognize that the estimated domestic climate benefits presented for this rule are based on evolving methodologies and depend in important respects on assumptions that are uncertain and subject to further revision with improvements in the science and modeling of climate change impacts. These uncertainties are discussed in greater detail in Chapter 4.3 and Chapter 7 of this RIA. Chapter 7 explains the methodology, modeling, and assumptions that inform the social cost of carbon estimates used here, identifies key uncertainties, and presents a sensitivity analysis exploring how the monetized climate benefits of the final rule would change under different assumptions. Under certain assumptions, as presented in that analysis, the climate benefits of this action exceed its compliance costs. Nonetheless, the EPA is not relying on social cost of carbon estimates to support this action and presents these data solely for informational purposes in compliance with E.O. 12866.[7] Excluded from this comparison are the benefit impacts from direct $PM_{2.5}$, SO_2 and NO_X emission changes that are projected to accompany the CO_2 changes.[8] Table 6-4 presents a summary of the PV and EAV of costs, domestic climate benefits, and net benefits associated with the targeted pollutant (i.e., CO_2).

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[6] While the benefits are limited to the targeted pollutant, the cost as discussed above is the change in generation cost for the entire power sector plus MR&R costs. The costs reported in Table 6-4 are not limited solely to those costs that occur at the sources regulated by this final rule.

[7] See *Portland Cement Ass'n v. Train*, 513 F.2d 506, 508 (D.C. Cir. 1975) (benefit-cost analysis not required under CAA section 111(a)(1).

[8] When considering whether a regulatory action is a potential welfare improvement (i.e., potential Pareto improvement) it is necessary to consider all impacts of the action.

Table 6-4 Present Value and Equivalent Annualized Value of Compliance Costs, Benefits, and Net Benefits Associated with Targeted Pollutant (CO_2), Illustrative Policy Scenario, 3 and 7 Percent Discount Rates, 2023-2037 (millions of 2016$)

	Costs		Domestic Climate Benefits		Net Benefits associated with the Targeted Pollutant (CO_2)	
	3%	**7%**	**3%**	**7%**	**3%**	**7%**
2023	22	17	-	-	(22)	(17)
2024	12	8.4	-	-	(12)	(8.4)
2025	220	150	60	6.7	(160)	(140)
2026	210	140	59	6.5	(150)	(130)
2027	200	130	59	6.2	(140)	(120)
2028	190	110	53	5.5	(130)	(110)
2029	180	110	52	5.3	(130)	(100)
2030	180	100	52	5.1	(130)	(95)
2031	170	93	51	4.9	(120)	(88)
2032	170	87	50	4.8	(120)	(83)
2033	15	7.4	41	3.8	26	(3.6)
2034	14	6.9	40	3.6	26	(3.3)
2035	14	6.4	40	3.5	26	(3.0)
2036	13	6.0	39	3.4	26	(2.7)
2037	13	5.6	39	3.2	26	(2.4)
Present Value	**1,600**	**970**	**640**	**62**	**(980)**	**(910)**
Equivalent Annualized Value	**140**	**110**	**53**	**6.9**	**(82)**	**(100)**

Note: Negative net benefits indicate forgone net benefits. All estimates are rounded to two significant figures, so figures may not sum due to independent rounding.

6.3.2.2 Net Benefits Including Air Pollutant Co-Benefits

When considering whether a regulatory action is a potential welfare improvement (i.e., potential Pareto improvement) it is necessary to consider all impacts of the action. Therefore, tables in this section provide the estimates of the benefits, costs, and net benefits of the illustrative policy scenario, inclusive of the benefit impacts from the direct $PM_{2.5}$, SO_2 and NO_X emission changes that are projected to accompany the CO_2 changes. In these tables, the estimates for the ancillary health co-benefits are derived using $PM_{2.5}$ log-linear concentration-response functions that quantify risk associated with the full range of $PM_{2.5}$ exposures experienced by the population.

Table 6-5 contains PV and EAV estimates of compliance costs, benefits, and net benefits inclusive of ancillary health co-benefits for the illustrative policy scenario.

Table 6-5 Present Value and Equivalent Annualized Value of Compliance Costs, Benefits (Inclusive of Health Co-Benefits), and Net Benefits, Illustrative Policy Scenario, 3 and 7 Percent Discount Rates, 2023-2037 (millions of 2016$)

	Costs		Benefits		Net Benefits	
	3%	**7%**	**3%**	**7%**	**3%**	**7%**
2023	22	17	0 to 0	0 to 0	(22)	(17)
2024	12	8.4	0 to 0	0 to 0	(12)	(8.4)
2025	220	150	350 to 780	190 to 470	130 to 560	43 to 320
2026	210	140	350 to 770	180 to 450	140 to 560	44 to 310
2027	200	130	340 to 770	170 to 430	140 to 560	45 to 300
2028	190	110	370 to 840	190 to 450	190 to 650	72 to 340
2029	180	110	370 to 830	180 to 430	190 to 650	72 to 320
2030	180	100	370 to 830	170 to 410	190 to 650	71 to 310
2031	170	93	360 to 820	160 to 390	190 to 650	69 to 300
2032	170	87	360 to 820	160 to 380	200 to 650	69 to 290
2033	15	7.4	350 to 800	150 to 360	330 to 780	140 to 350
2034	14	6.9	350 to 790	140 to 340	330 to 780	130 to 340
2035	14	6.4	340 to 790	130 to 330	330 to 770	130 to 320
2036	13	6.0	340 to 780	130 to 310	330 to 770	120 to 310
2037	13	5.6	340 to 770	120 to 300	320 to 760	120 to 290
Present Value	**1,600**	**970**	**4,600 to 10,000**	**2,100 to 5,000**	**3,000 to 8,800**	**1,100 to 4,100**
Equivalent Annualized Value	**140**	**110**	**390 to 870**	**230 to 550**	**250 to 730**	**120 to 450**

Note: Negative net benefits indicate forgone net benefits. All estimates are rounded to two significant figures, so figures may not sum due to independent rounding.

6.3.2.3 Net Benefits Including Air Pollution Co-Benefits Calculated According to Sensitivity Analysis Assumptions

Table 6-6 and Table 6-7 report the estimated benefits, costs, and net benefits of the illustrative policy scenario according to different sensitivity analysis assumptions. These results reflect different assumptions regarding the relationship between $PM_{2.5}$ exposure and the risk of premature death, as detailed in Chapter 4. In Table 6-5, we report the net benefits calculated using the sum of the estimated ozone and $PM_{2.5}$-related benefits using a no-threshold concentration-response parameter for $PM_{2.5}$. In Table 6-6, we report the net benefits calculated using the sum of the estimated ozone and $PM_{2.5}$-related benefits assuming that the $PM_{2.5}$-

attributable risks fall to zero below the lowest measured levels of the two long-term $PM_{2.5}$ mortality studies used to quantify risk. In Table 6-7, we report the net benefits calculated using the sum of the estimated ozone and $PM_{2.5}$-related benefits assuming that $PM_{2.5}$ related benefits fall to zero below the $PM_{2.5}$ National Ambient Air Quality Standard (NAAQS). These are PV and EAV estimates, similar to the presentation of results in Table 6-5.

The EPA has generally expressed a greater confidence in the effects observed around the mean $PM_{2.5}$ concentrations in the long-term epidemiological studies; this does not necessarily imply a concentration threshold below which there are no effects. As such, these analyses are designed to increase transparency rather than imply a specific lower bound on the size of the ancillary health co-benefits. As noted at the beginning of this Chapter, there are additional important benefit impacts that the EPA could not monetize.

Table 6-6 Present Value and Equivalent Annualized Value of Compliance Costs, Benefits, and Net Benefits assuming that Mortality Risk $PM_{2.5}$ Related Benefits Fall to Zero Below the Lowest Measured Level of Each Long-Term $PM_{2.5}$ Mortality Study, Illustrative Policy Scenario, 3 and 7 Percent Discount Rates, 2023-2037 (millions of 2016$)

	Costs		**Benefits Excluding Benefits below LML**		**Net Benefits Excluding Benefits below LML**	
	3%	**7%**	**3%**	**7%**	**3%**	**7%**
2023	22	17	-	-	(22)	(17)
2024	12	8.4	-	-	(12)	(8.4)
2025	220	150	340 to 420	180 to 240	120 to 200	36 to 93
2026	210	140	340 to 410	180 to 230	130 to 200	38 to 92
2027	200	130	330 to 410	170 to 220	130 to 210	39 to 91
2028	190	110	340 to 390	170 to 200	150 to 200	54 to 89
2029	180	110	340 to 390	160 to 190	160 to 210	54 to 87
2030	180	100	330 to 390	150 to 190	160 to 210	53 to 86
2031	170	93	330 to 380	150 to 180	160 to 210	53 to 84
2032	170	87	330 to 380	140 to 170	160 to 210	54 to 83
2033	15	7.4	310 to 390	130 to 170	300 to 370	120 to 160
2034	14	6.9	310 to 380	130 to 160	300 to 370	120 to 160
2035	14	6.4	310 to 380	120 to 160	290 to 370	110 to 150
2036	13	6.0	310 to 380	110 to 150	290 to 360	110 to 140
2037	13	5.6	300 to 370	110 to 140	290 to 360	100 to 130
Present Value	**1,600**	**970**	**4,200 to 5,100**	**1,900 to 2,400**	**2,600 to 3,500**	**920 to 1,400**
Equivalent Annualized Value	**140**	**110**	**350 to 420**	**210 to 260**	**220 to 290**	**100 to 160**

Note: Negative net benefits indicate forgone net benefits. All estimates are rounded to two significant figures, so figures may not sum due to independent rounding.

Table 6-7 Present Value and Equivalent Annualized Value of Compliance Costs, Benefits, and Net Benefits assuming that Mortality Risk $PM_{2.5}$ Related Benefits Fall to Zero Below the $PM_{2.5}$ National Ambient Air Quality Standard, Illustrative Policy Scenario, 3 and 7 Percent Discount Rates, 2023-2037 (millions of 2016$)

	Costs		Benefits Excluding Benefits below $PM_{2.5}$ NAAQS		Net Benefits Excluding Benefits below $PM_{2.5}$ NAAQS	
	3%	**7%**	**3%**	**7%**	**3%**	**7%**
2023	22	17	-	-	(22)	(17)
2024	12	8.4	-	-	(12)	(8.4)
2025	220	150	120 to 250	45 to 140	(99) to 33	(100) to (12)
2026	210	140	120 to 250	43 to 130	(94) to 41	(95) to (5.8)
2027	200	130	110 to 250	41 to 130	(89) to 46	(88) to (2.2)
2028	190	110	100 to 220	35 to 110	(86) to 34	(79) to (6.2)
2029	180	110	100 to 220	34 to 100	(82) to 38	(73) to (3.3)
2030	180	100	100 to 220	32 to 99	(77) to 42	(68) to (0.44)
2031	170	93	98 to 220	31 to 95	(73) to 45	(63) to 1.2
2032	170	87	98 to 220	29 to 91	(69) to 49	(58) to 3.6
2033	15	7.4	92 to 220	29 to 93	77 to 200	22 to 85
2034	14	6.9	91 to 220	28 to 89	76 to 200	21 to 82
2035	14	6.4	90 to 210	27 to 85	76 to 200	20 to 79
2036	13	6.0	89 to 210	25 to 81	75 to 200	19 to 75
2037	13	5.6	87 to 210	24 to 77	74 to 200	19 to 71
Present Value	**1,600**	**970**	**1,300 to 2,900**	**420 to 1,300**	**(330) to 1,300**	**(550) to 340**
Equivalent Annualized Value	**140**	**110**	**110 to 240**	**47 to 140**	**(27) to 110**	**(60) to 38**

Note: Negative net benefits indicate forgone net benefits. All estimates are rounded to two significant figures, so figures may not sum due to independent rounding.

6.4 References

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CHAPTER 7: APPENDIX - UNCERTAINTY ASSOCIATED WITH ESTIMATING THE SOCIAL COST OF CARBON

7.1 Overview of Methodology Used to Develop Interim Domestic SC-CO_2 Estimates

The domestic SC-CO_2 estimates rely on the same ensemble of three integrated assessment models (IAMs) that were used to develop the IWG global SC-CO_2 estimates (DICE 2010, FUND 3.8, and PAGE 2009).[1] The three IAMs translate emissions into changes in atmospheric greenhouse concentrations, atmospheric concentrations into changes in temperature, and changes in temperature into economic damages. The emissions projections used in the models are based on specified socio-economic (GDP and population) pathways. These emissions are translated into atmospheric concentrations, and concentrations are translated into warming based on each model's simplified representation of the climate and a key parameter, equilibrium climate sensitivity. The effect of the changes is estimated in terms of consumption-equivalent economic damages. As in the IWG exercise, three key inputs were harmonized across the three models: a probability distribution for equilibrium climate sensitivity; five scenarios for economic, population, and emissions growth; and discount rates.[2] All other model features were left unchanged. Future damages are discounted using constant discount rates of both 3 and 7 percent, as recommended by OMB Circular A-4. The domestic share of the global SC-CO_2 – i.e., an approximation of the climate change impacts that occur within U.S. borders – are calculated directly in both FUND and PAGE. However, DICE 2010 generates only global SC-CO_2 estimates. Therefore, the EPA approximated U.S. damages as 10 percent of the global values from the DICE model runs, based on the results from a regionalized version of the model (RICE 2010) reported in Table 2 of Nordhaus (2017).[3]

The steps involved in estimating the social cost of CO_2 are as follows. The three integrated assessment models (FUND, DICE, and PAGE) are run using the harmonized

[1] The full models' names are as follows: Dynamic Integrated Climate and Economy (DICE); Climate Framework for Uncertainty, Negotiation, and Distribution (FUND); and Policy Analysis of the Greenhouse Gas Effect (PAGE).
[2] See the IWG's summary of its methodology in the 2015 Clean Power Plan docket, document ID number EPA-HQ-OAR-2013-0602-37033, "Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866, Interagency Working Group on Social Cost of Carbon (May 2013, Revised July 2015)". See also National Academies (2017) for a detailed discussion of each of these modeling assumptions.
[3] Nordhaus, William D. 2017. Revisiting the social cost of carbon. Proceedings of the National Academy of Sciences of the United States, 114(7): 1518-1523.

equilibrium climate sensitivity distribution, five socioeconomic and emissions scenarios, constant discount rates described above. Because the climate sensitivity parameter is modeled probabilistically, and because PAGE and FUND incorporate uncertainty in other model parameters, the final output from each model run is a distribution over the SC-CO_2 in year t based on a Monte Carlo simulation of 10,000 runs. For each of the IAMs, the basic computational steps for calculating the social cost estimate in a particular year t is 1.) calculate the temperature effects and (consumption-equivalent) damages in each year resulting from the baseline path of emissions; 2.) adjust the model to reflect an additional unit of emissions in year t; 3.) recalculate the temperature effects and damages expected in all years beyond t resulting from this adjusted path of emissions, as in step 1; and 4.) subtract the damages computed in step 1 from those in step 3 in each model period and discount the resulting path of marginal damages back to the year of emissions. In PAGE and FUND step 4 focuses on the damages attributed to the US region in the models. As noted above, DICE does not explicitly include a separate US region in the model and therefore, the EPA approximates U.S. damages in step 4 as 10 percent of the global values based on the results of Nordhaus (2017). This exercise produces 30 separate distributions of the SC-CO_2 for a given year, the product of 3 models, 2 discount rates, and 5 socioeconomic scenarios. Following the approach used by the IWG, the estimates are equally weighted across models and socioeconomic scenarios in order to reduce the dimensionality of the results down to two separate distributions, one for each discount rate.

7.2 Treatment of Uncertainty in Interim Domestic SC-CO_2 Estimates

There are various sources of uncertainty in the SC-CO_2 estimates used in this RIA. Some uncertainties pertain to aspects of the natural world, such as quantifying the physical effects of greenhouse gas emissions on Earth systems. Other sources of uncertainty are associated with current and future human behavior and well-being, such as population and economic growth, GHG emissions, the translation of Earth system changes to economic damages, and the role of adaptation. It is important to note that even in the presence of uncertainty, scientific and economic analysis can provide valuable information to the public and decision makers, though the uncertainty should be acknowledged and when possible taken into account in the analysis

(National Academies 2013).[4] OMB Circular A-4 also requires a thorough discussion of key sources of uncertainty in the calculation of benefits and costs, including more rigorous quantitative approaches for higher consequence rules. This section summarizes the sources of uncertainty considered in a quantitative manner in the domestic SC-CO_2 estimates.

The domestic SC-CO_2 estimates consider various sources of uncertainty through a combination of a multi-model ensemble, probabilistic analysis, and scenario analysis. We provide a summary of this analysis here; more detailed discussion of each model and the harmonized input assumptions can be found in the 2017 National Academies report. For example, the three IAMs used collectively span a wide range of Earth system and economic outcomes to help reflect the uncertainty in the literature and in the underlying dynamics being modeled. The use of an ensemble of three different models at least partially addresses the fact that no single model includes all of the quantified economic damages. It also helps to reflect structural uncertainty across the models, which is uncertainty in the underlying relationships between GHG emissions, Earth systems, and economic damages that are included in the models. Bearing in mind the different limitations of each model and lacking an objective basis upon which to differentially weight the models, the three integrated assessment models are given equal weight in the analysis.

Monte Carlo techniques were used to run the IAMs a large number of times. In each simulation the uncertain parameters are represented by random draws from their defined probability distributions. In all three models the equilibrium climate sensitivity is treated probabilistically based on the probability distribution from Roe and Baker (2007) calibrated to the IPCC AR4 consensus statement about this key parameter.[5] The equilibrium climate sensitivity is a key parameter in this analysis because it helps define the strength of the climate response to increasing GHG concentrations in the atmosphere. In addition, the FUND and PAGE models define many of their parameters with probability distributions instead of point estimates. For these two models, the model developers' default probability distributions are maintained for all parameters other than those superseded by the harmonized inputs (i.e., equilibrium climate

[4] Institute of Medicine of the National Academies. 2013. Environmental Decisions in the Face of Uncertainty. The National Academies Press.
[5] Specifically, the Roe and Baker distribution for the climate sensitivity parameter was bounded between 0 and 10 with a median of 3 °C and a cumulative probability between 2 and 4.5 °C of two-thirds.

sensitivity, socioeconomic and emissions scenarios, and discount rates). More information on the uncertain parameters in PAGE and FUND is available upon request.

For the socioeconomic and emissions scenarios, uncertainty is included in the analysis by considering a range of scenarios selected from the Stanford Energy Modeling Forum exercise, EMF-22. Given the dearth of information on the likelihood of a full range of future socioeconomic pathways at the time the original modeling was conducted, and without a basis for assigning differential weights to scenarios, the range of uncertainty was reflected by simply weighting each of the five scenarios equally for the consolidated estimates. To better understand how the results vary across scenarios, results of each model run are available in the docket.

The outcome of accounting for various sources of uncertainty using the approaches described above is a frequency distribution of the SC-CO_2 estimates for emissions occurring in a given year for each discount rate. Unlike the approach taken for consolidating results across models and socioeconomic and emissions scenarios, the SC-CO_2 estimates are not pooled across different discount rates because the range of discount rates reflects both uncertainty and, at least in part, different policy or value judgements; uncertainty regarding this key assumption is discussed in more detail below. The frequency distributions reflect the uncertainty around the input parameters for which probability distributions were defined, as well as from the multi-model ensemble and socioeconomic and emissions scenarios where probabilities were implied by the equal weighting assumption. It is important to note that the set of SC-CO_2 estimates obtained from this analysis does not yield a probability distribution that fully characterizes uncertainty about the SC-CO_2 due to impact categories omitted from the models and sources of uncertainty that have not been fully characterized due to data limitations.

Figure 7-1 presents the frequency distribution of the domestic SC-CO_2 estimates for emissions in 2030 for each discount rate. Each distribution represents 150,000 estimates based on 10,000 simulations for each combination of the three models and five socioeconomic and emissions scenarios. In general, the distributions are skewed to the right and have long right tails, which tend to be longer for lower discount rates. To highlight the difference between the impact of the discount rate on the SC-CO_2 and other quantified sources of uncertainty, the bars below the frequency distributions provide a symmetric representation of quantified variability in the

$SC\text{-}CO_2$ estimates conditioned on each discount rate. The full set of $SC\text{-}CO_2$ results through 2050 is available in the docket.

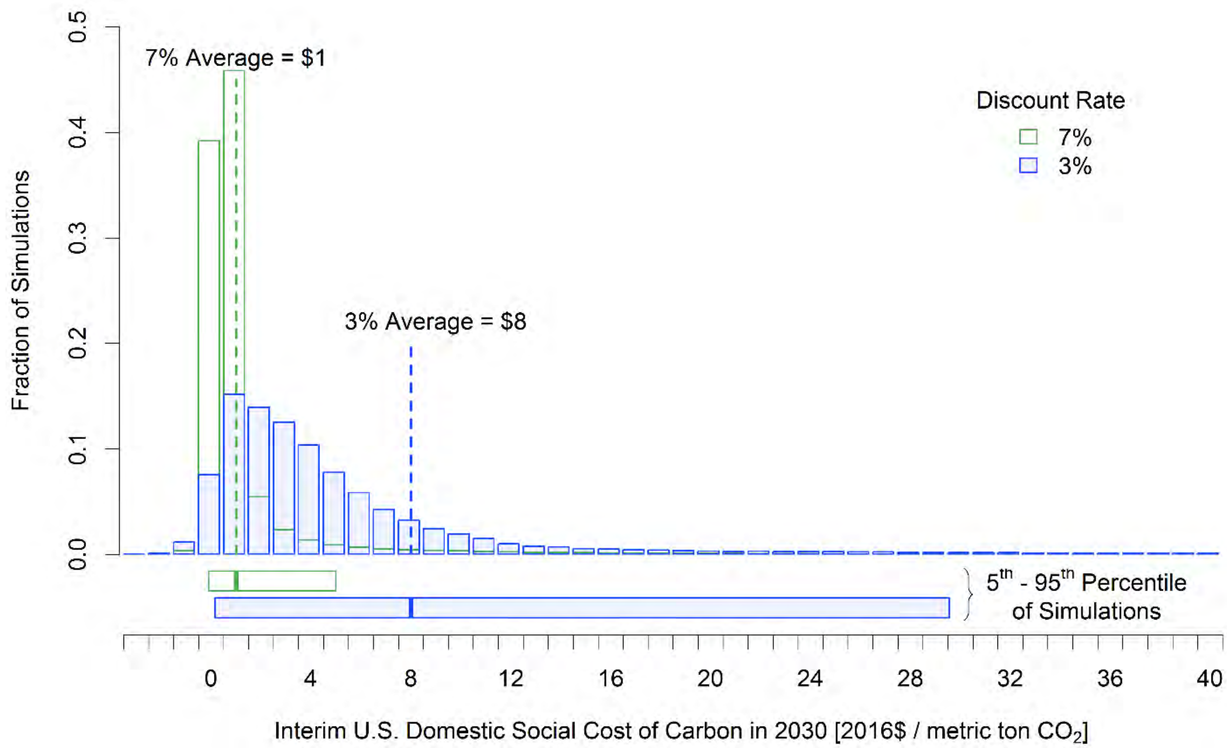

Figure 7-1 Frequency Distribution of Interim Domestic SC-CO2 Estimates for 2030 (in 2016$ per metric ton CO_2)

As illustrated by the frequency distributions in Figure 7-1, the assumed discount rate plays a critical role in the ultimate estimate of the social cost of carbon. This is because CO_2 emissions today continue to impact society far out into the future, so with a higher discount rate, costs that accrue to future generations are weighted less, resulting in a lower estimate. Circular A-4 recommends that costs and benefits be discounted using the rates of 3 percent and 7 percent to reflect the opportunity cost of consumption and capital, respectively. Circular A-4 also recommends quantitative sensitivity analysis of key assumptions[6], and offers guidance on what sensitivity analysis can be conducted in cases where a rule will have important intergenerational benefits or costs. To account for ethical considerations of future generations and potential uncertainty in the discount rate over long time horizons, Circular A-4 suggests "further

[6] "If benefit or cost estimates depend heavily on certain assumptions, you should make those assumptions explicit and carry out sensitivity analyses using plausible alternative assumptions." (OMB 2003, page 42).

sensitivity analysis using a lower but positive discount rate in addition to calculating net benefit using discount rates of 3 and 7 percent" (page 36) and notes that research from the 1990s suggests intergenerational rates "from 1 to 3 percent per annum" (OMB 2003). We consider the uncertainty in this key assumption by calculating the domestic SC-CO_2 based on a 2.5 percent discount rate, in addition to the 3 and 7 percent used in the main analysis. Using a 2.5 percent discount rate, the average domestic SC-CO_2 estimate across all the model runs for emissions occurring over 2025-2035 ranges from $10 to $12 per metric ton of CO_2 (2016$). In this case the domestic climate benefits in 2025 are $120 million under the illustrative policy scenario; by 2035, the estimated benefits decrease to $100 million under the illustrative policy scenario.

In addition to the approach to accounting for the quantifiable uncertainty described above, the scientific and economics literature has further explored known sources of uncertainty related to estimates of the SC-CO_2. For example, researchers have published papers that explore the sensitivity of IAMs and the resulting SC-CO_2 estimates to different assumptions embedded in the models (see, e.g., Hope (2013), Anthoff and Tol (2013), and Nordhaus (2014)). However, there remain additional sources of uncertainty that have not been fully characterized and explored due to remaining data limitations. Additional research is needed in order to expand the quantification of various sources of uncertainty in estimates of the SC-CO_2 (e.g., developing explicit probability distributions for more inputs pertaining to climate impacts and their valuation). On the issue of intergenerational discounting, some experts have argued that a declining discount rate would be appropriate to analyze impacts that occur far into the future (Arrow et al., 2013). However, additional research and analysis is still needed to develop a methodology for implementing a declining discount rate and to understand the implications of applying these theoretical lessons in practice. The 2017 National Academies report also provides recommendations pertaining to discounting, emphasizing the need to more explicitly model the uncertainty surrounding discount rates over long time horizons, its connection to uncertainty in economic growth, and, in turn, to climate damages using a Ramsey-like formula (National Academies 2017). These and other research needs are discussed in detail in the 2017 National Academies' recommendations for a comprehensive update to the current methodology, including a more robust incorporation of uncertainty.

7.3 Global Climate Benefits

In addition to requiring reporting of impacts at a domestic level, OMB Circular A-4 states that when an agency "evaluate[s] a regulation that is likely to have effects beyond the borders of the United States, these effects should be reported separately" (page 15).[7] This guidance is relevant to the valuation of damages from CO_2 and other GHGs, given that GHGs contribute to damages around the world independent of the country in which they are emitted. Therefore, in this section we present the global climate benefits in 2030 from this proposed rulemaking using the global SC-CO_2 estimates corresponding to the model runs that generated the domestic SC-CO_2 estimates used in the main analysis. The average global SC-CO_2 estimate across all the model runs for emissions occurring over 2025-2035 range from $6 to $9 per metric ton of CO_2 emissions (in 2016 dollars) using a 7 percent discount rate, and $53 to $63 per metric ton of CO_2 emissions (2016$) using a 3 percent discount rate. The domestic SC-CO_2 estimates presented above are approximately 19 percent and 14 percent of these global SC-CO_2 estimates for the 7 percent and 3 percent discount rates, respectively.

Applying these estimates to the CO_2 emission reductions results in estimated global climate benefits in 2025 of $70 million (2016$) under the illustrative policy scenario, using a 7 percent discount rate; this increases to $590 million (2016$) under the illustrative policy scenario, using a 3 percent discount rate. By 2035, the global climate benefits are estimated at $77 million (2016$) under the illustrative policy scenario, using a 7 percent discount rate. Using a 3 percent discount rate, this increases to $530 million under the illustrative policy scenario.

Under the sensitivity analysis considered above using a 2.5 percent discount rate, the average global SC-CO_2 estimate across all the model runs for emissions occurring over 2025-2035 ranges from $77 to $90 per metric ton of CO_2 (2016$); in this case the global climate

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[7] While Circular A-4 does not elaborate on this guidance, the basic argument for adopting a domestic only perspective for the central benefit-cost analysis of domestic policies is based on the fact that the authority to regulate only extends to a nation's own residents who have consented to adhere to the same set of rules and values for collective decision-making, as well as the assumption that most domestic policies will have negligible effects on the welfare of other countries' residents (EPA 2010; Kopp et al. 1997; Whittington et al. 1986). In the context of policies that are expected to result in substantial effects outside of U.S. borders, an active literature has emerged discussing how to appropriately treat these impacts for purposes of domestic policymaking (e.g., Gayer and Viscusi 2016, 2017; Anthoff and Tol, 2010; Fraas et al. 2016; Revesz et al. 2017). This discourse has been primarily focused on the regulation of greenhouse gases (GHGs), for which domestic policies may result in impacts outside of U.S. borders due to the global nature of the pollutants.

benefits in 2025 are \$870 million (2016\$) under the illustrative policy scenario; by 2035, the global benefits in this sensitivity case decrease to \$760 million (2016\$) under the illustrative policy scenario.

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CHAPTER 8: APPENDIX – AIR QUALITY MODELING

8.1 Air Quality Modeling Platform

In this section we describe the air quality modeling platform that was used to support the benefits analysis for this final rule. As part of this assessment we used existing air quality modeling for 2011 and 2023 to estimate $PM_{2.5}$ and ozone concentrations in 2025, 2030, and 2035 for both the baseline and illustrative policy scenario identified in Chapter 4. The modeling platform consists of several components including the air quality model, meteorology, estimates of international transport, and base year and future year emissions from anthropogenic and natural sources. An overview of each of these platform comments is provided in the subsections below.

8.1.1 Air Quality Model, Meteorology and Boundary Conditions

We used the Comprehensive Air Quality Model with Extensions (CAMx version 6.40) with the Carbon Bond chemical mechanism CB6r4 for modeling base year and future year ozone and $PM_{2.5}$ concentrations (Ramboll, 2016). CAMx is a three-dimensional grid-based photochemical air quality model designed to simulate the formation and fate of oxidant precursors, primary and secondary particulate matter concentrations, and deposition over national, regional and urban spatial scales. Consideration of the different processes (e.g., transport and deposition) that affect primary (directly emitted) and secondary (formed by atmospheric processes) pollutants in different locations is fundamental to understanding and assessing the effects of emissions on air quality concentrations.

The geographic extent of the modeling domain covers the 48 contiguous states along with the southern portions of Canada and the northern portions of Mexico as shown in 8-1. This modeling domain contains 25 vertical layers with a top at about 17,550 meters[1] and horizontal grid resolution of 12 km x 12 km. The model simulations produce hourly air quality concentrations for each 12-km grid cell across the modeling domain.

[1] Since the model top is defined based on atmospheric pressure, the actual height of the model top varies somewhat with time and location.

Figure 8-1 Air Quality Modeling Domain

The 2011 meteorological data for air quality modeling were derived from running Version 3.4 of the Weather Research Forecasting Model (WRF) (Skamarock, et al., 2008). The meteorological outputs from WRF include hourly-varying horizontal wind components (i.e., speed and direction), temperature, moisture, vertical diffusion rates, and rainfall rates for each vertical layer in each grid cell. The 2011 meteorology was used for both the 2011 base year and 2023 future year air quality modeling. Details of the annual 2011 meteorological model simulation and evaluation are provided in a separate technical support document (US EPA, 2014a) which can be obtained at:
http://www.epa.gov/ttn/scram/reports/MET_TSD_2011_final_11-26-14.pdf

The lateral boundary and initial species condition concentrations are provided by a three-dimensional global atmospheric chemistry model, GEOS-Chem (Yantosca, 2004) standard version 8-03-02 with 8-02-01 chemistry. The global GEOS-Chem model simulates atmospheric chemical and physical processes driven by assimilated meteorological observations from the NASA's Goddard Earth Observing System (GEOS-5).[2] GEOS-Chem was run for 2011 with a grid resolution of 2.0 degrees x 2.5 degrees (latitude-longitude). The predictions were used to provide one-way dynamic boundary condition concentrations at three-hour intervals and an initial concentration field for the CAMx simulations. The 2011 boundary concentrations from

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[2] Additional information available at:
http://gmao.gsfc.nasa.gov/GEOS/ and http://wiki.seas.harvard.edu/geos-chem/index.php/GEOS-5).

GEOS-Chem were used for both the 2011 and 2023 model simulations. The procedures for translating GEOS-Chem predictions to initial and boundary concentrations are described elsewhere (Henderson, 2014). More information about the GEOS-Chem model and other applications using this tool is available at: http://www-as.harvard.edu/chemistry/trop/geos.

8.1.2 2011 and 2023 Emissions

The purpose of the 2011 current year modeling is to represent the year 2011 in a manner consistent with the methods used in corresponding future-year cases, including the 2023 future year base case. The emissions data in this platform are primarily based on the 2011National Emissions Inventory (NEI) v2 for point sources, nonpoint sources, commercial marine vessels, nonroad mobile sources and fires. The onroad mobile source emissions are similar to those in the 2011 NEIv2, but were generated using the 2014a version of the Motor Vehicle Emissions Simulator (MOVES2014a) (http://www.epa.gov/otaq/models/moves/). The 2011 and 2023 emission inventories incorporate revisions implemented based on comments received on the Notice of Data Availability (NODA) issued in January 2017 "Preliminary Interstate Ozone Transport Modeling Data for the 2015 Ozone National Ambient Air Quality Standard" (82 FR 1733), along with revisions made from prior notices and rulemakings on earlier versions of the 2011 platform. The preparation of the emission inventories for air quality modeling is described in the Technical Support Document (TSD) Additional Updates to Emissions Inventories for the Version 6.3, 2011 Emissions Modeling Platform for the Year 2023 (US EPA, 2017a). Electronic copies of the emission inventories and ancillary data used to produce the emissions inputs to the air quality model are available from the 2011en and 2023en section of the EPA Air Emissions Modeling website for the 2011v6.3 emissions modeling platform: https://www.epa.gov/air-emissions-modeling/2011-version-63-platform.

The emission inventories for the future year of 2023 were developed using projection methods that are specific to the type of emission source. Future emissions are projected from the 2011 current year either by running models to estimate future year emissions from specific types of emission sources (e.g., EGUs, and onroad and nonroad mobile sources), or for other types of sources by adjusting the base year emissions according to the best estimate of changes expected to occur in the intervening years. For sectors which depend strongly on meteorology (such as biogenic and fires), the same emissions are used in the base and future years to be consistent with the 2011 meteorology used when modeling 2023. For the remaining sectors, rules and specific legal obligations that go into effect in the intervening years, along with changes in activity for the sector, are considered when possible. Emissions inventories for neighboring countries used in our modeling are included in this platform, specifically 2011 and 2023 emissions inventories for Mexico, and 2013 and 2025 emissions inventories for Canada. The meteorological data used to create and temporalize emissions for the future year cases is held constant and represents the year 2011. The same ancillary data files[3] are used to prepare the future year emissions inventories for air quality modeling as were used to prepare the 2011 base year inventories with the exception of chemical speciation profiles for mobile sources and temporal profiles for EGUs.

The projected EGU emissions reflect the emissions reductions expected due to the Final Mercury and Air Toxics (MATS) rule announced on December 21, 2011, the Cross-State Air Pollution Rule (CSAPR) issued July 6, 2011, and the CSAPR Update issued October 26, 2016. The 2023 EGU projected inventory was developed using an engineering analysis approach. The EPA started with 2016 reported, seasonal, historical emissions for each unit. The emissions data for NO_X and SO_2 for units that report data under either the Acid Rain Program (ARP) and/or the CSAPR were aggregated to the summer/ozone season period (May-September) and winter/non-ozone period (January-April and October-December).[4] Adjustments to 2016 levels were made to account for retirements, coal to gas conversion, retrofits, state-of-the-art combustion controls, along with other unit-specific adjustments. Details and these adjustments, and information about handling for units not reporting under Part 75 and pollutants other than NO_X and SO_2 are described in the emissions modeling TSD (US EPA, 2017a).

The 2023 non-EGU stationary source emissions inventory includes impacts from enforceable national rules and programs including the Reciprocating Internal Combustion Engines (RICE) and cement manufacturing National Emissions Standards for Hazardous Air Pollutants (NESHAPs) and Boiler Maximum Achievable Control Technology (MACT) reconsideration reductions. Projection factors and percent reductions for non-EGU point sources reflect comments received by the EPA in response to the January 2017 NODA, along with

[3] Ancillary data files include temporal, spatial, and VOC/$PM_{2.5}$ chemical speciation surrogates.
[4] The EPA notes that historical state-level ozone season EGU NO_X emission rates are publicly available and quality assured data. They are monitored using continuous emissions monitors (CEMs) data and are reported to the EPA directly by power sector sources. They are reported under Part 75 of the CAA.

emissions reductions due to national and local rules, control programs, plant closures, consent decrees and settlements. Growth and control factors provided by states and by regional organizations on behalf of states were applied. Reductions to criteria air pollutant (CAP) emissions from stationary engines resulting as co-benefits to the Reciprocating Internal Combustion Engines (RICE) National Emission Standard for Hazardous Air Pollutants (NESHAP) are included. Reductions due to the New Source Performance Standards (NSPS) VOC controls for oil and gas sources, and the NSPS for process heaters, internal combustion engines, and natural gas turbines were also included.

For point and nonpoint oil and gas sources, state projection factors were generated using historical oil and gas production data available for 2011 to 2015 from EIA and information from AEO 2017 projections to year 2023. Co-benefits of stationary engines CAP reductions (RICE NESHAP) and controls from New Source Performance Standards (NSPS) are reflected for select source categories. Mid-Atlantic Regional Air Management Association (MARAMA) factors for the year 2023 were used where applicable. Projection factors for other nonpoint sources such as stationary source fuel combustion, industrial processes, solvent utilization, and waste disposal, reflect emissions reductions due to control programs along with comments on the growth and control of these sources as a result of the January 2017 NODA and information gathered from prior rulemakings and outreach to states on emission inventories.

The MOVES2014a-based 2023 onroad mobile source emissions account for changes in activity data and the impact of on-the-books national rules including: the Tier 3 Vehicle Emission and Fuel Standards Program, the 2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards (LD GHG), the Renewable Fuel Standard (RFS2), the Mobile Source Air Toxics Rule, the Light Duty Green House Gas/Corporate Average Fuel Efficiency (CAFE) standards for 2012-2016, the Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles, the Light-Duty Vehicle Tier 2 Rule, and the Heavy-Duty Diesel Rule. The MOVES-based emissions also include state rules related to the adoption of LEV standards, inspection and maintenance programs, Stage II refueling controls, and local fuel restrictions.

The nonroad mobile 2023 emissions, including railroads and commercial marine vessel emissions also include all national control programs. These control programs include the Clean Air Nonroad Diesel Rule – Tier 4, the Nonroad Spark Ignition rules, and the Locomotive-Marine Engine rule. For ocean-going vessels (Class 3 marine), the emissions data reflect the 2005 voluntary Vessel Speed Reduction (VSR) within 20 nautical miles, the 2007 and 2008 auxiliary engine rules, the 40 nautical mile VSR program, the 2009 Low Sulfur Fuel regulation, the 2009-2018 cold ironing regulation, the use of 1 percent sulfur fuel in the Emissions Control Area (ECA) zone, the 2012-2015 Tier 2 NO_X controls, the 2016 0.1 percent sulfur fuel regulation in ECA zone, and the 2016 International Marine Organization (IMO) Tier 3 NO_X controls. Non-U.S. and U.S. category 3 commercial marine emissions were projected to 2025 using consistent methods that incorporated controls based on ECA and IMO global NO_X and SO_2 controls.

8.1.3 2011 Model Evaluation for Ozone and $PM_{2.5}$

An operational model performance evaluation was conducted to examine the ability of the 2011 base year model run to simulate the corresponding 2011 measured ozone and $PM_{2.5}$ concentrations. This evaluation focused on four statistical metrics comparing model predictions to the corresponding observations. The performance statistics include mean bias, mean error, normalized mean bias, and normalized mean error. Mean bias (MB) is the sum of the difference (predicted – observed) divided by the total number of replicates (*n*). Mean bias is given in units of ppb and is defined as:

$$\mathrm{MB} = \frac{1}{n}\sum_{1}^{n}(P - O) \qquad \text{(Eq-1)}$$

Where:

- P is the model-predicted concentration;
- O is the observed concentrations; and
- n is the total number of observations

Mean error (ME) calculates the sum of the absolute value of the difference (predicted - observed) divided by the total number of replicates (*n*). Mean error is given in units of ppb and is defined as:

$$\text{ME} = \frac{1}{n}\sum_1^n |P - O| \quad \text{(Eq-2)}$$

Normalized mean bias (NMB) is the sum of the difference (predicted - observed) over the sum of observed values. NMB is a useful model performance indicator because it avoids over inflating the observed range of values, especially at low concentrations. Normalized mean bias is given in percentage units and is defined as:

$$\text{NMB} = \frac{\sum_1^n (P - O)}{\sum_1^n (O)} * 100 \quad \text{(Eq-3)}$$

Normalized mean error (NME) is the sum of the absolute value of the difference (predicted - observed) divided by the sum of observed values. Normalized mean error is given in percentage units and is defined as:

$$\text{NME} = \frac{\sum_1^n |P - O|}{\sum_1^n (O)} * 100 \quad \text{(Eq-4)}$$

For $PM_{2.5}$, performance statistics were calculated for modeled and observed 24-hour average concentrations paired by day and location for the entire year. Performance statistics were calculated for monitoring data in the Chemical Speciation Network (CSN)[5] and, separately, for monitoring data in the Interagency Monitoring of Protected Visual Environments (IMPROVE)[6] network. For ozone, performance statistics were calculated for modeled concentrations with observed 8-hour daily maximum (MDA8) ozone concentrations at or above 60 ppb[7] over the period May through September for monitoring sites in the Air Quality System (AQS)[8,9] network. For both $PM_{2.5}$ and ozone, the modeled and predicted pairs of data were aggregated by 9 regions

[5] Additional information on the measurements made at CSN monitoring sites can be found at the following web link: https://www.epa.gov/amtic/chemical-speciation-network-csn.
[6] Additional information on the measurements made at IMPROVE monitoring sites can be found at the following web link: https://www3.epa.gov/ttnamti1/visdata.html.
[7] Performance statistics are calculated for days with measured values at or above 60 ppb in order to focus the evaluation on days with high rather than low concentrations.
[8] Additional information on the measurements made at AQS monitoring sites can be found at the following web link: https://www.epa.gov/aqs.
[9] Note that the AQS data base also includes measurements made at monitoring sites in the Clean Air Status and Trends Network (CASTNet).

across the U.S. for the calculation of model performance statistics. These 9 regions are shown in Figure 8-2.[10]

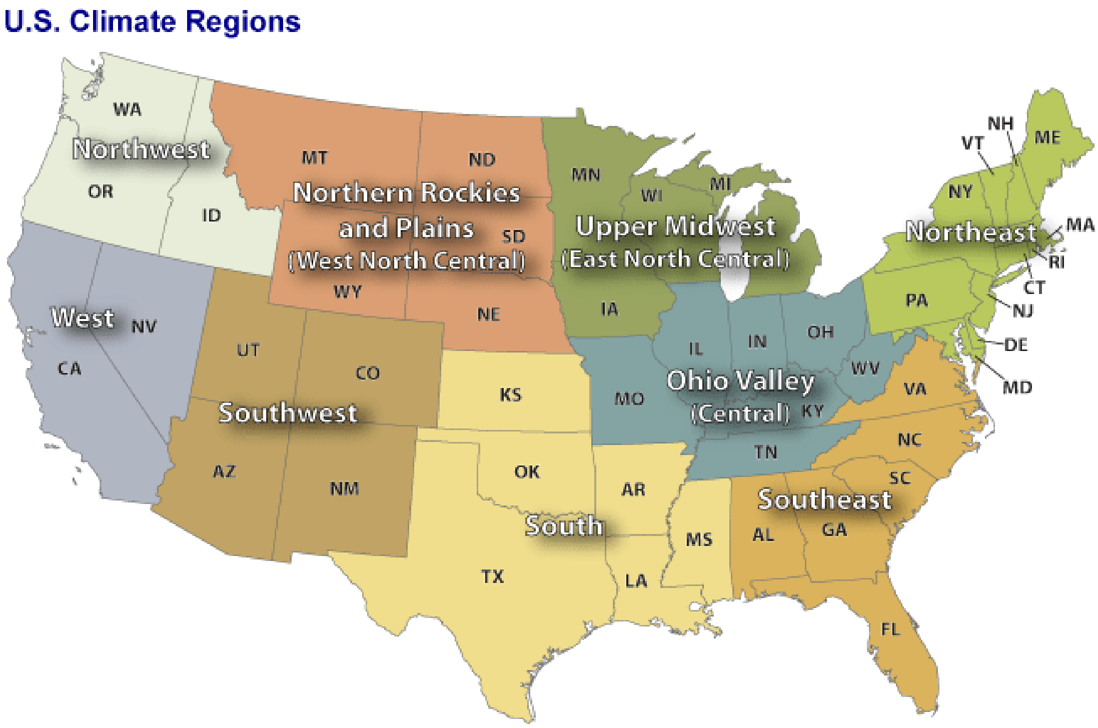

Figure 8-2 **NOAA Climate Regions**

Model performance statistics for $PM_{2.5}$ for each region are provided in Table 8-1. These data indicate that over the year as a whole, $PM_{2.5}$ is over predicted in the Northeast, Ohio Valley, Upper Midwest, Southeast, and Northwest regions and under predicted in the South and Southwest regions. Normalized mean bias is within ±30 percent in all regions except the Northwest which has somewhat larger model over-predictions. Model performance for $PM_{2.5}$ for the 2011 modeling platform is similar to the model performance results for other contemporary, state of the science photochemical model applications (Simon et al., 2012). Additional details on $PM_{2.5}$ model performance for the 2011 base year model run can be found in the Technical Support Document for EPA's preliminary regional haze modeling (US EPA, 2017b).

[10] Source: http://www.ncdc.noaa.gov/monitoring-references/maps/us-climate-regions.php#references.

Table 8-1 Model Performance Statistics by Region for $PM_{2.5}$

Region	Network	No. of Obs	MB ($\mu g/m^3$)	ME ($\mu g/m^3$)	NMB (%)	NME (%)
Northeast	IMPROVE	1577	0.87	2.21	17.70	44.90
	CSN	2788	0.97	4.04	9.70	40.40
Ohio Valley	IMPROVE	680	0.10	2.96	1.20	35.50
	CSN	2475	0.13	3.85	1.10	32.80
Upper Midwest	IMPROVE	700	0.83	2.37	14.20	40.40
	CSN	1343	1.37	3.66	13.60	36.30
Southeast	IMPROVE	1172	0.52	3.54	6.30	43.20
	CSN	1813	0.19	3.92	1.70	34.20
South	IMPROVE	933	-0.47	2.69	-6.50	37.40
	CSN	962	-0.08	4.48	-0.75	39.50
Southwest	IMPROVE	3695	-1.12	1.86	-28.00	46.30
	CSN	746	-0.08	3.93	-1.00	47.10
N. Rockies/ Plains	IMPROVE	1952	0.07	1.39	2.40	44.90
	CSN	275	-2.07	4.18	-21.80	43.90
Northwest	IMPROVE	1901	1.19	2.28	43.20	82.90
	CSN	668	5.77	7.25	69.90	87.90
West	IMPROVE	1782	-1.08	2.08	-25.30	48.50
	CSN	936	-2.92	5.08	-23.10	40.30

Model performance statistics for May through September MDA8 ozone concentrations for each region are provided in Table 8-2. Overall, measured ozone is under predicted in most regions, except for the Northeast and Southeast where over prediction is found. Normalized mean bias is within ±15 percent in all regions. Model performance for ozone for the 2011 modeling platform is similar to the model performance results for other contemporary, state of the science photochemical model applications (Simon et al., 2012). Additional details on ozone model performance for the 2011 base year model run can be found in the Air Quality Technical Support Document for EPA's preliminary interstate ozone transport modeling for the 2015 ozone National Ambient Air Quality Standard (US EPA, 2017c).

Table 8-2 Model Performance Statistics by Region for Ozone on Days Above 60 ppb (May-Sep)

Region	No. of Obs	MB (ppb)	ME (ppb)	NMB (%)	NME (%)
Northeast	4085	1.20	7.30	1.80	10.70
Ohio Valley	6325	-0.60	7.50	-0.90	11.10
Upper Midwest	1162	-4.00	7.60	-5.90	11.10
Southeast	4840	2.30	6.80	3.40	10.20
South	5694	-5.30	8.40	-7.60	12.20
Southwest	6033	-6.20	8.50	-9.40	12.90
N. Rockies/Plains	380	-7.20	8.40	-11.40	13.40
Northwest	79	-5.60	9.00	-8.70	14.00
West	8655	-8.60	10.30	-12.20	14.50

Thus, the model performance results demonstrate the scientific credibility of our 2011 modeling platform for predicting $PM_{2.5}$ and ozone concentrations. These results provide confidence in the ability of the modeling platform to provide a reasonable projection of expected future year ozone concentrations and contributions.

8.2 Source Apportionment Tags

As described in Chapter 4, CAMx source apportionment modeling was used to track ozone and $PM_{2.5}$ component species impacts from pre-defined groups of emissions sources (source tags). Separate tags were created for state-level EGUs split by fuel type (coal units versus non-coal units[11]). For some states with low EGU emissions, EGUs are grouped with nearby states that also have low EGU emissions. In addition, there are no coal EGUs operating in the 2023 emissions case for the following states: Idaho, Oregon, and Washington. Therefore, there is no coal EGU tag for those states. Similarly, there were no EGUs (coal or non-coal) in Washington D.C. in the 2023 emissions scenario, so there were no EGU tags for Washington D.C. There were also several domain-wide tags for sources other than EGUs. Table 8-3 provides a full list of the emissions group tags that were tracked in the source apportionment modeling

[11] For the purposes of this analysis non-coal fuels include emissions from natural gas, oil, biomass, and waste coal-fired EGUs.

Table 8-3 Source Apportionment Tags

Coal-fired EGU tags	Non-coal EGU tags	Domain-wide tags
• Alabama • Arizona • Arkansas • California • Colorado • Connecticut + Rhode Island • Delaware + New Jersey • Florida • Georgia • Illinois • Indiana • Iowa • Kansas • Kentucky • Louisiana • Maine + Mass. + New Hamp. + Vermont • Maryland • Michigan • Minnesota • Mississippi • Missouri • Montana • Nebraska • Nevada • New Mexico • New York • North Carolina • North Dakota + South Dakota • Ohio • Oklahoma • Pennsylvania • South Carolina • Tennessee • Texas • Utah • Virginia • West Virginia • Wisconsin • Wyoming • Tribal Data*	• Alabama • Arizona • Arkansas • California • Colorado • Connecticut + Rhode Island • Delaware + New Jersey • Florida • Georgia • Idaho + Oregon + Washington • Illinois • Indiana • Iowa • Kansas • Kentucky • Louisiana • Maine + Mass. + New Hamp. + Vermont • Maryland • Michigan • Minnesota • Mississippi • Missouri • Montana • Nebraska • Nevada • New Mexico • New York • North Carolina • North Dakota + South Dakota • Ohio • Oklahoma • Pennsylvania • South Carolina • Tennessee • Texas • Utah • Virginia • West Virginia • Wisconsin • Wyoming • Tribal Data[12]	• EGU retirements through 2025 • EGU retirements 2026-2030 • All U.S. anthropogenic emissions from source sectors other than EGUs • International within-domain emissions (sources occurring in Canada, Mexico, and from offshore marine vessels and drilling platforms) • Fires (wildfires and prescribed fires) • Biogenic sources • Boundary conditions

Examples of the magnitude and spatial extent of ozone tagged contributions are provided in Figure 8-3 through Figure 8-6 for coal and non-coal EGUs in Pennsylvania and Texas. These figures show how both the magnitude and the spatial patterns of contributions can differ between coal and non-coal EGU units within a state and downwind. In addition, the figures demonstrate that the spatial extent of contributions can vary substantially from state to state depending on the location of sources, the magnitude of their emissions, and meteorology. Moreover, day to day variations in meteorology can have a substantial impact on day to day patterns in contributions, which we capture in our analysis. While we used the daily contributions in our calculations, seasonal average contributions are presented here to provide a general illustration of the differential spatial patterns of contribution.

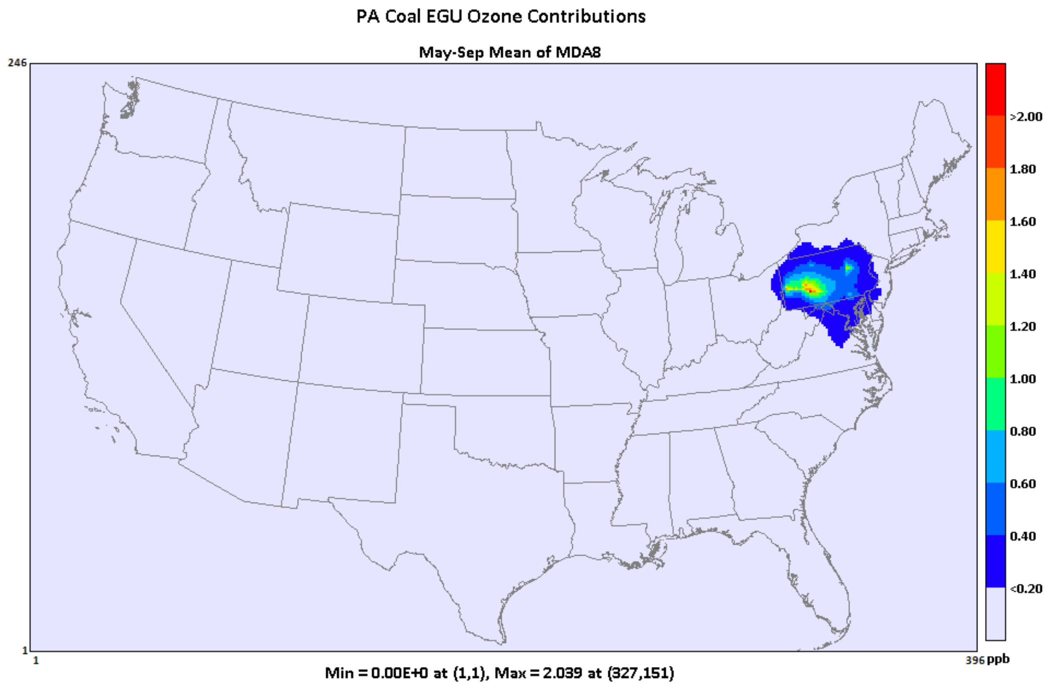

Figure 8-3 Map of Pennsylvania Coal EGU Tag Contribution to Seasonal Average MDA8 Ozone (ppb)

[12] EGUs operating on tribal lands were tracked together in a single tag. There are EGUs on tribal land in the following states: Utah (coal), New Mexico (coal), Arizona (coal and non-coal), Idaho (non-coal). EGU emissions occurring on tribal lands were not included in the state-level EGU source tags.

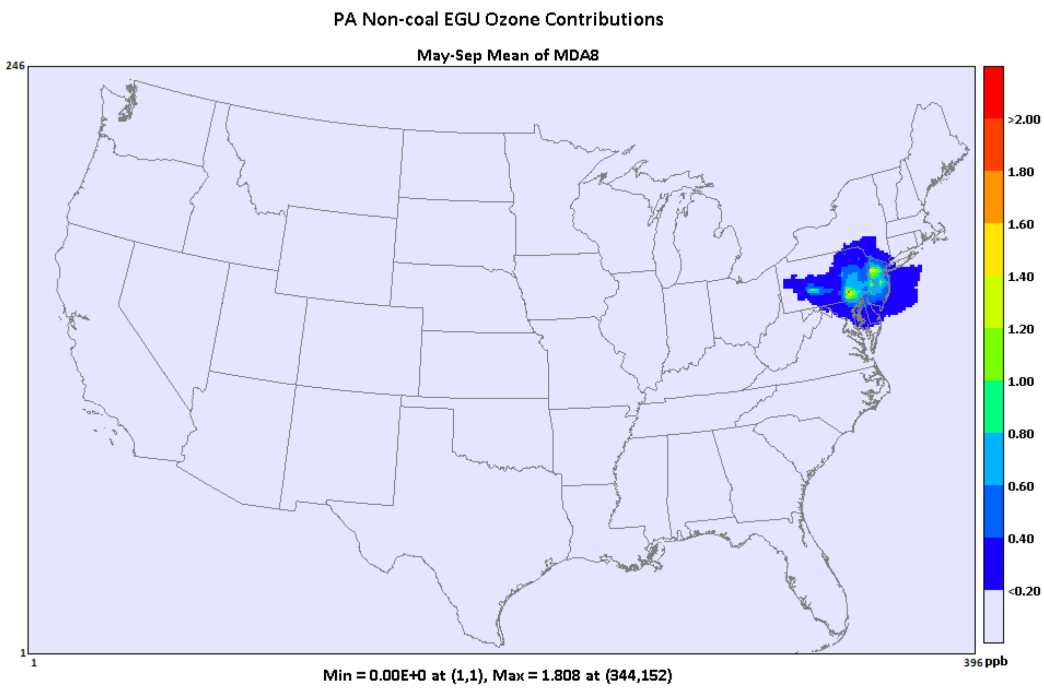

Figure 8-4 **Map of Pennsylvania Non-Coal EGU Tag Contribution to Seasonal Average MDA8 Ozone (ppb)**

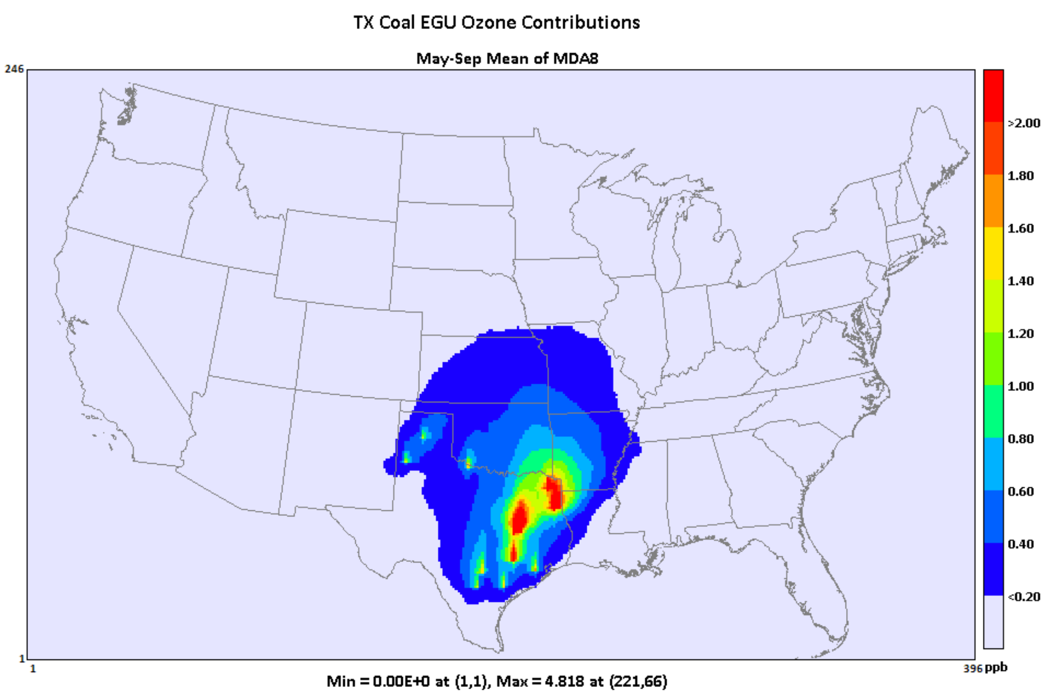

Figure 8-5 **Map of Texas Coal EGU Tag Contribution to Seasonal Average MDA8 Ozone (ppb)**

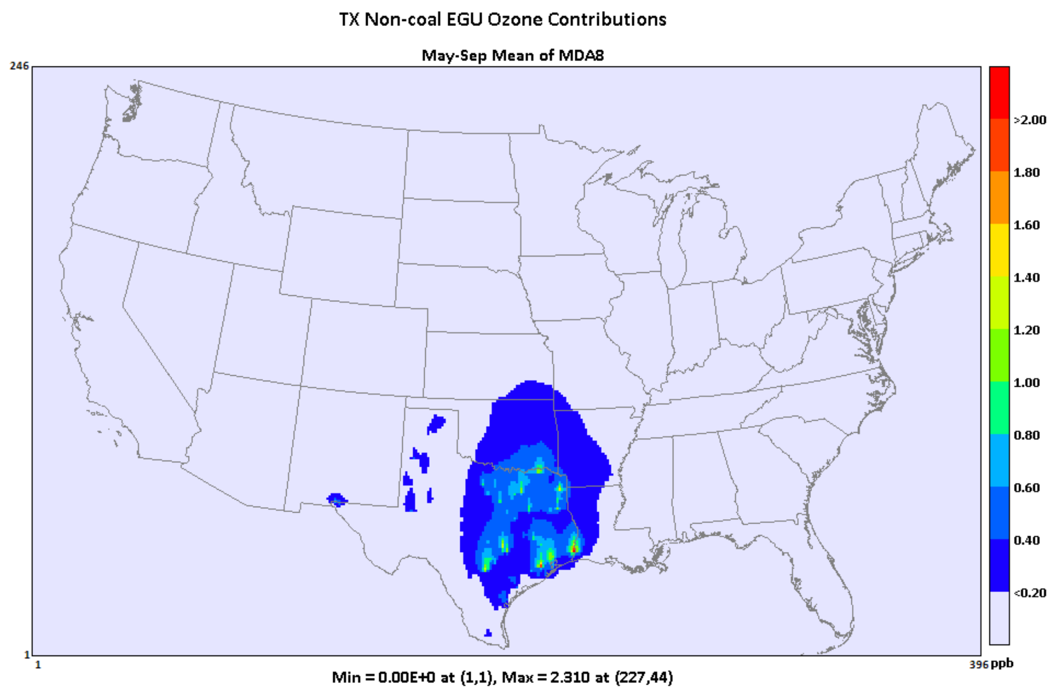

Figure 8-6 Map of Texas Non-Coal EGU Tag Contribution to Seasonal Average MDA8 Ozone (ppb)

Examples of the magnitude and spatial extent of tagged contributions for $PM_{2.5}$ component species are provided in Figure 8-7 through Figure 8-12. Examples are provided for coal-fired EGUs in Indiana. These figures show how both the magnitude and the spatial patterns of contributions can differ by season and by $PM_{2.5}$ component species. The species which are formed through chemical reactions in the atmosphere (sulfate and nitrate) have a more regional signal than directly emitted primary $PM_{2.5}$ (organic aerosol (OA), elemental carbon (EC), and crustal material[13]) whose impact is more local in nature. In addition, the chemistry and transport can vary by season with nitrate contributions being higher in the winter than in the summer and sulfate contributions being higher in the summer than in the winter.

[13] Crustal material refers to metals that are commonly found in the earth's crust such as Aluminum, Calcium, Iron, Magnesium, Manganese, Potassium, Silicon, Titanium and the associated oxygen atoms.

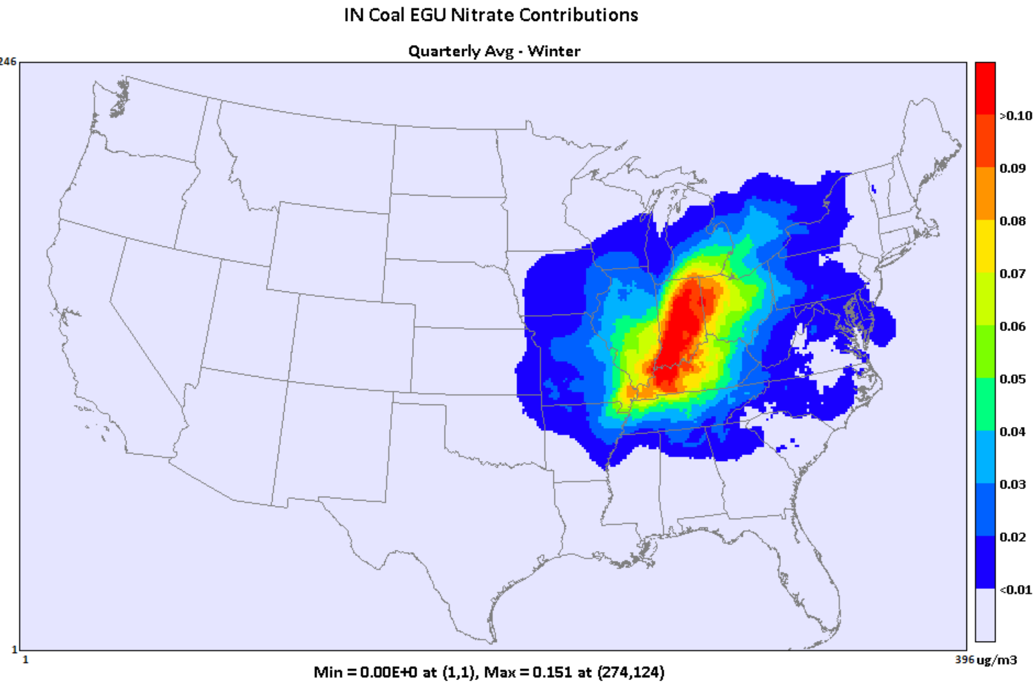

Figure 8-7 Map of Indiana Coal EGU Tag Contributions to Wintertime Average (January-March) Nitrate (µg/m^3)

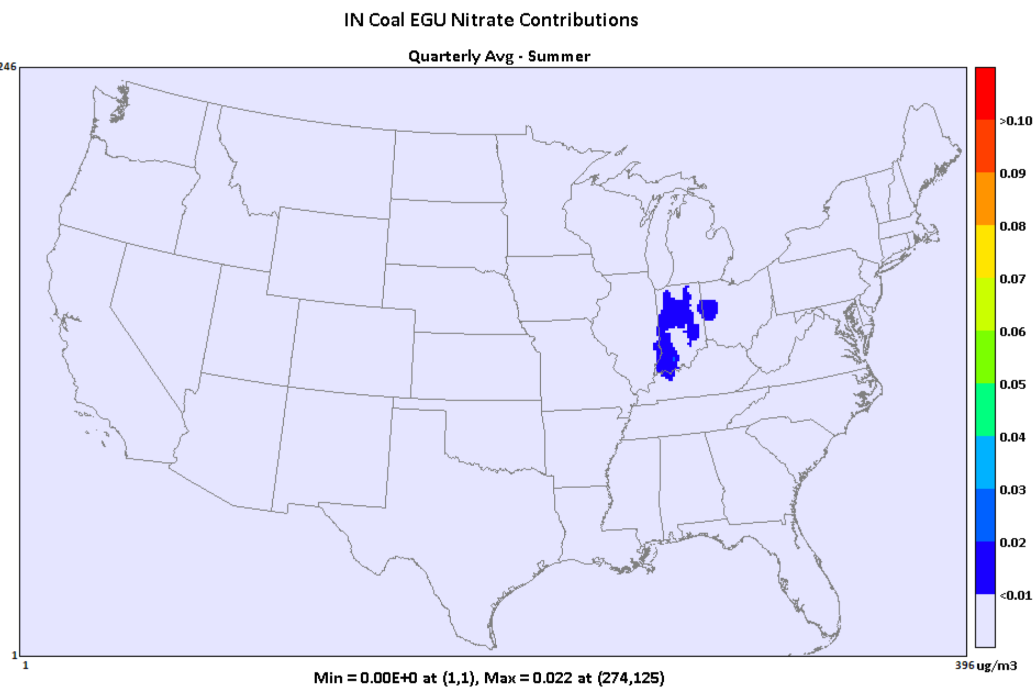

Figure 8-8 Map of Indiana Coal EGU Tag Contributions to Summertime Average (July-September) Nitrate (µg/m^3)

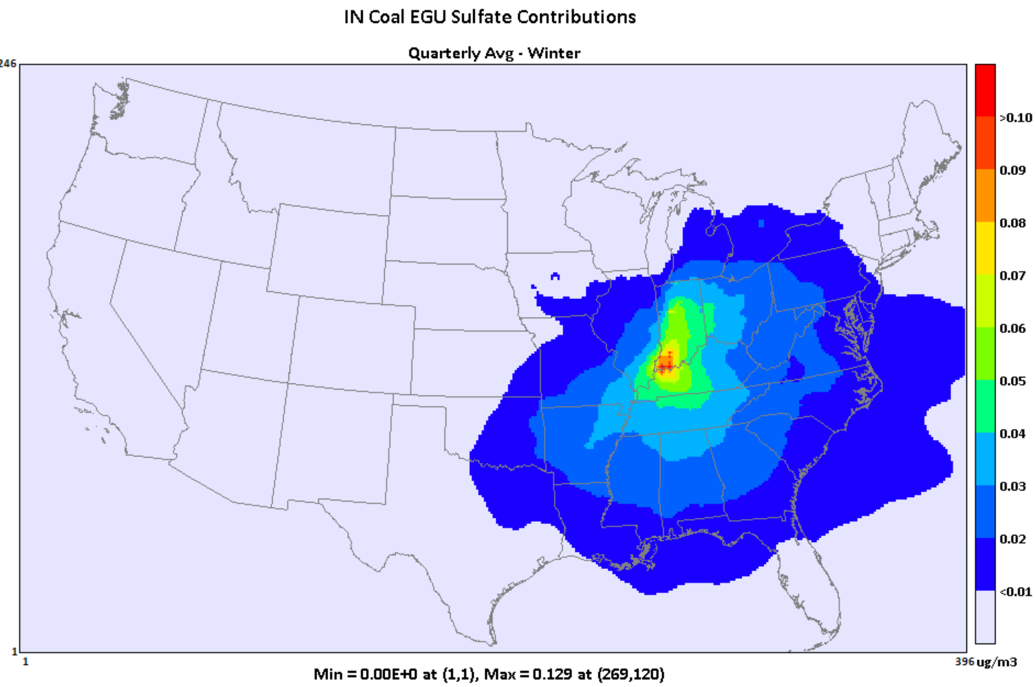

Figure 8-9 Map of Indiana Coal EGU Tag Contributions to Wintertime Average (January-March) Sulfate (µg/m^3)

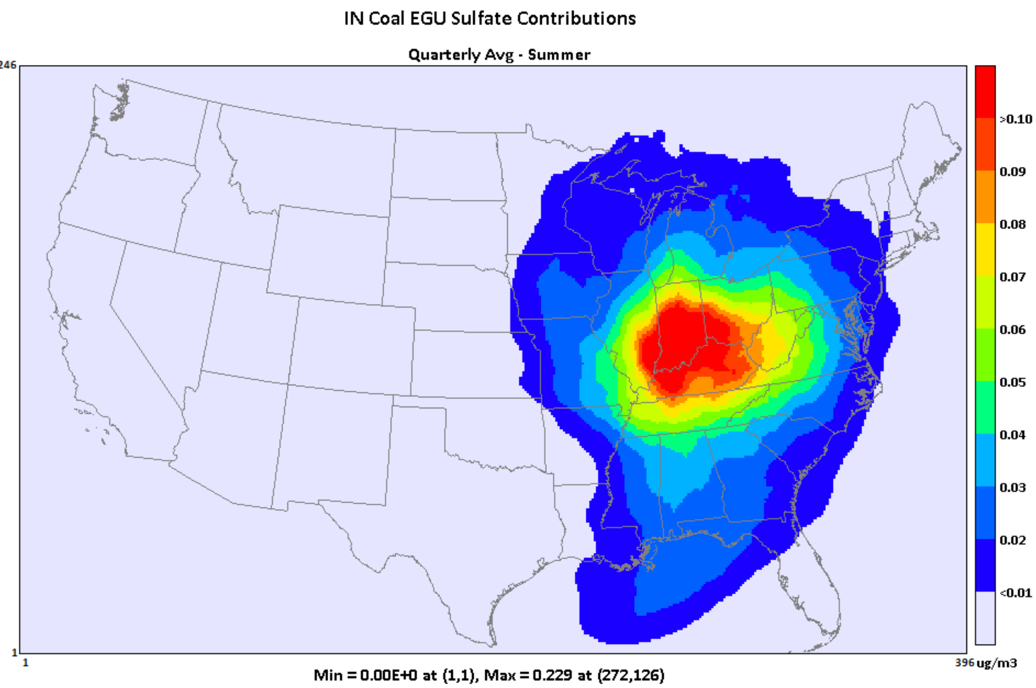

Figure 8-10 Map of Indiana Coal EGU Tag Contributions to Summertime Average (July-September) Sulfate (µg/m^3)

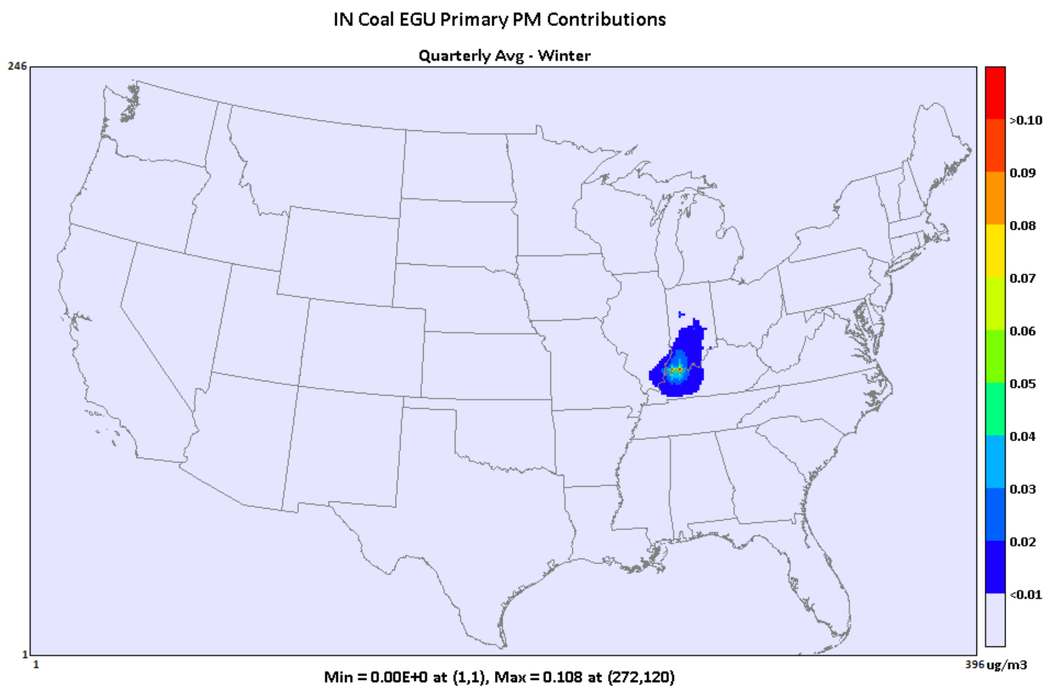

Figure 8-11 Map of Indiana Coal EGU Tag Contributions to Wintertime Average (January-March) Primary $PM_{2.5}$ ($\mu g/m^3$)

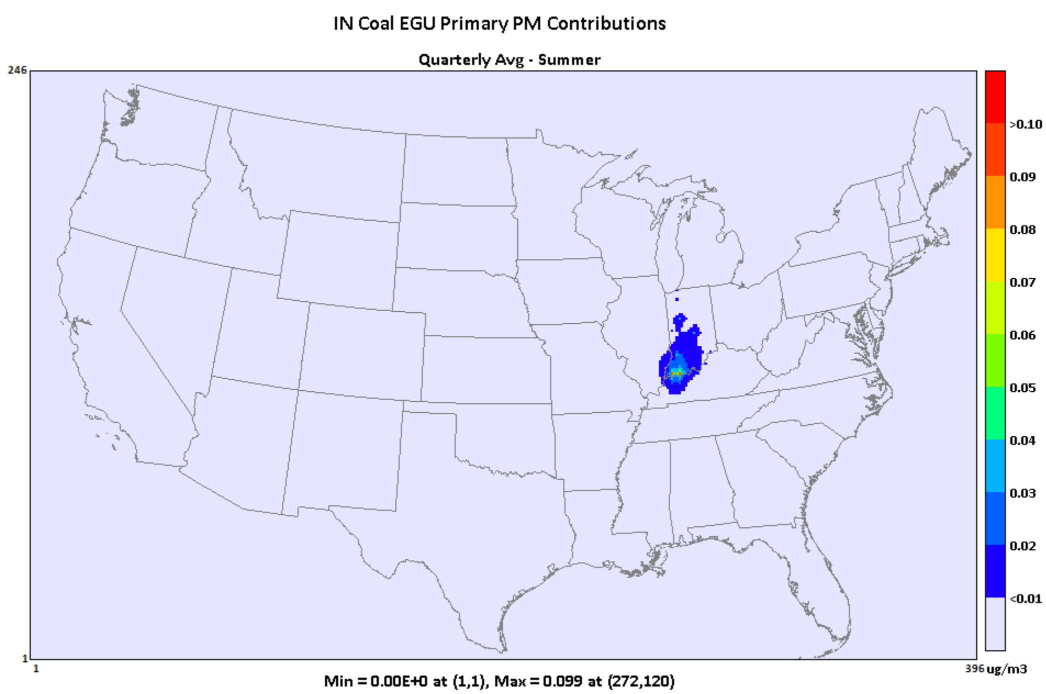

Figure 8-12 Map of Indiana Coal EGU Tag Contributions to Summertime Average (July-September) Primary $PM_{2.5}$ ($\mu g/m^3$)

The contributions represent the spatial and temporal distribution of the emissions within each source tag. Thus, the contribution modeling results do not allow us to represent any changes to any "within tag" spatial distributions. For example, the location of coal-fired EGUs in Michigan are held in place based on locations in the 2023 emissions. Additionally, the relative magnitude of sources within a source tag do not change from what was modeled with the 2023 emissions inventory.

8.3 Applying Source Apportionment Contributions to Create Air Quality Fields for the Baseline and Illustrative Policy Scenario

As explained in Chapter 4, we created air quality surfaces for the future year baseline and illustrative policy scenario by scaling the EGU sector tagged contributions from the 2023 modeling based on relative changes in EGU emissions associated with each tagged category between the 2023 emissions case and the baseline or illustrative policy scenario of interest. The following subsections describe in more detail the emissions used to represent each scenario and provide equations used to apply these scaling ratios along with tables of the ratios.

8.3.1 Estimation methods for Emissions that Represent the Baseline and Illustrative Policy Scenario

Annual NO_X, SO_2, and heat input by state and fuel (coal and noncoal) as well as ozone season[14] NO_X by state and fuel were obtained for the baseline and illustrative policy scenario described in Chapter 3. In addition to NO_X and SO_2, emissions, $PM_{2.5}$ emissions were also needed for the baseline and illustrative policy scenario. Since these were not generated by IPM, we estimated $PM_{2.5}$ emissions by using the ratio of 2023 heat input for combustion-based EGUs[15] to the heat input of each scenario from combustion-based EGUs to scale the 2023 $PM_{2.5}$. However, 2023 heat input totals were only available for units with Continuous Emissions Monitoring Systems (CEMS) data so an additional scalar was used to adjust the CEMS heat value before the $PM_{2.5}$ emissions are calculated as follows. First, the following data were obtained:

[14] For the purpose of this analysis the ozone season is defined as the months of May-September

[15] Heat input for nuclear units and other non-combustion based EGUs that do not emit $PM_{2.5}$ were not included in any heat input numbers described in this chapter.

- Projected 2023 CEMS heat input values (MMBtu) by ORIS facility and unit ID[16] along with Carbon Monoxide (CO) and $PM_{2.5}$ emissions (tons/yr) for each CEMS unit

- 2023 EGU total CO and $PM_{2.5}$ emissions (tons/yr) by state and fuel type

- Baseline and illustrative policy scenario heat input values (MMBtu) by state and fuel type

Next, the CEMS EGU unit-level emissions values for CO and $PM_{2.5}$ were aggregated to state and fuel type. Since CO emissions correlate with heat input, the ratio of CO from all EGUs to CO from CEMS units in each state-fuel category was used to scale CEMS heat inputs to represent total EGU heath input for combustion units as shown in Equation (5) and Equation (6).

$$2023\ Heat\ Scalar_{state,fuel} = \frac{Total\ 2023\ EGU\ CO_{state,fuel}}{2023\ CEMS\ CO_{state,fuel}} \quad \text{(Eq-5)}$$

$$Total\ 2023\ Heat_{state,fuel} = 2023\ Heat\ Scalar_{state,fuel} \times 2023\ CEMS\ Heat_{state,fuel} \quad \text{(Eq-6)}$$

Finally, using Equation (7) and Equation (8), the 2023 $PM_{2.5}$ emissions were scaled to represent $PM_{2.5}$ emissions for the baseline and illustrative policy scenario based on relative changes in heat input from 2023 (as obtained by Equation 6).

$$PM_{2.5}\ Scalar_{scenario,state,fuel} = \frac{IPM\ Heat_{scenario,state,fuel}}{Total\ 2023\ Heat_{state,fuel}} \quad \text{(Eq-7)}$$

$$PM_{2.5\ scenario,state,fuel} = PM_{2.5}\ Scalar_{scenario,state,fuel} *\ 2023\ EGU\ PM_{2.5\ state,fuel} \quad \text{(Eq-8)}$$

For states and fuels without CEMS CO data or where 2023 CO emissions equal zero, the 2023 EGU $PM_{2.5}$ value was passed through to the baseline or illustrative policy scenario unchanged. This was the case for North Dakota non-coal and California coal only.

One limitation of this methodology was identified after emissions scaling was complete. Waste coal units were included in the non-coal EGU tags. There are 3 states in which some EGUs are fueled by waste coal: Montana, Pennsylvania and West Virginia. Only in West

[16] Data obtained from files available at: https://www.cmascenter.org/smoke/documentation/4.5/html/ch02s09s19.html

Virginia do the majority of non-coal primary $PM_{2.5}$ emissions come from waste coal. The baseline and illustrative policy scenario predict substantial growth compared to 2023 in non-coal heat input in West Virginia from natural gas units which have low $PM_{2.5}$ emissions rates. The methodology described above scales $PM_{2.5}$ emissions from relatively high emitting waste coal EGUs in West Virginia to predict new heat input from lower emitting natural gas EGUs. Therefore, this methodology likely overestimates the direct $PM_{2.5}$ emissions associated with non-coal EGUs in West Virginia for the baseline and the illustrative policy scenario. This was not as problematic for the two other states, Pennsylvania and Montana, with waste coal EGUs. In Pennsylvania, waste coal makes up a relatively small fraction of $PM_{2.5}$ emissions within the non-coal EGU tag. In Montana, non-coal EGU heat input is predicted to decrease substantially from 2023 levels in the baseline and illustrative policy scenario and therefore $PM_{2.5}$ emissions are predicted to be quite small.

As discussed above, EGU emissions occurring on tribal lands were tagged separately from state-level emissions in the 2023 source apportionment tracking. Since the IPM summaries included tribal emissions within the state (i.e. tribal emissions were not split-out from state emissions), we estimated tribal emissions by reallocating a portion of EGU emissions from Arizona, Idaho, New Mexico and Utah using the fraction of tribal emissions within each state from the 2023 emissions. For instance, emissions occurring on tribal lands accounted for 23 percent of total EGU NO_X from Utah, 17 percent of EGU NO_X from New Mexico, 36 percent of EGU NO_X from Arizona and 7 percent of EGU NO_X from Idaho in 2023. We use these percentages to estimate total EGU tribal NO_X emissions for the baseline and illustrative policy scenario for both coal and non-coal fuel types. We also adjust the state-level emissions to exclude those emissions from state totals so that our IPM break-outs match the definitions of the source apportionment tags. Table 8-4 provides fractions of EGU emissions coming from tribal lands for all pollutants and states. The relatively high scaling ratios for tribal non-coal EGU emissions shown in Table 8-5 thought Table 8-8, are the result of not breaking out the state-fractions by fuel type to calculate tribal emissions combined with the fact that tribal non-coal EGU emissions in 2023 were much smaller than tribal coal EGU emissions. However, since the ozone and $PM_{2.5}$ contributions from 2023 non-coal EGU units were extremely small, these large scaling factors did not have a noticeable impact on the final air quality surfaces.

Table 8-4 Tribal Fractions by State in the 2023 Emissions

State	NO_X	SO_2	$PM_{2.5}$
Arizona	0.36	0.20	0.38
Idaho	0.07	0.11	0.14
New Mexico	0.17	0.62	0.69
Utah	0.23	0.12	0.23

8.3.2 Scaling Ratio Applied to Source Apportionment Tags

Scaling ratios for $PM_{2.5}$ components that are emitted directly from the source (OA, EC, crustal) were based on relative changes in annual primary $PM_{2.5}$ emissions between the 2023 emissions case and the baseline and the illustrative policy scenario. Scaling ratios for components that are formed through chemical reactions in the atmosphere were created as follows: scaling ratios for sulfate were based on relative changes in annual SO_2 emissions; scaling ratios for nitrate were based on relative changes annual NO_X emissions; and scaling ratios for ozone formed in NO_X-limited regimes[17] ("O3N") were based on relative changes in ozone season (May-September) NO_X emissions. The scaling ratios that were applied to each species and scenario are provided in Table 8-5 through Table 8-8.[18]

Scaling ratios were applied to create air quality surfaces for ozone using equation (9):

$$\begin{aligned} Ozone_{m,g,d,i,y} = {} & C_{m,g,d,BC} + C_{m,g,d,int} + C_{m,g,d,bio} + C_{m,g,d,fires} \\ & + C_{m,g,d,USanthro} + C_{m,g,d,y,EGUret} + \sum_{t=1}^{T} C_{VOC,m,g,d,t} \\ & + \sum_{t=1}^{T} C_{NOx,m,g,d,t} S_{t,i,y} \end{aligned} \quad \text{(Eq-9)}$$

[17] The CAMx model internally determines whether the ozone formation regime is NO_X-limited or VOC-limited depending on predicted ratios of indicator chemical species.
[18] Note that while there were no EGU emissions from Washington D.C. in the 2023 source apportionment simulations, there were extremely small emissions predicted in the baseline and illustrative policy scenario (~1 ton per year of NO_X and 0 tons per year of SO_2,). Since the emissions were negligible and there was no associated source apportionment tag to scale to, we did not include any impact of Washington D.C. EGU emissions in the air quality surfaces.

where:

- $Ozone_{m,g,d,i,y}$ is the estimated ozone for metric, "m" (MDA8 or MDA1), grid-cell, "g", day, "d", scenario, "i", and year, "y";
- $C_{m,g,d,BC}$ is the total ozone contribution from the modeled boundary inflow; $C_{m,g,d,int}$ is the total ozone contribution from international emissions within the model domain;
- $C_{m,g,d,bio}$ is the total ozone contribution from biogenic emissions;
- $C_{m,g,d,fires}$ is the total ozone contribution from fires;
- $C_{m,g,d,USanthro}$ is the total ozone contribution from U.S. anthropogenic sources other than EGUs;
- $C_{m,g,d,y,EGUret}$ is the total ozone contribution from retiring EGUs after year, "y" (this term is equal to 0 in 2030 and 2035);
- $C_{VOC,m,g,d,t}$ is the ozone contribution from EGU emissions of VOCs from tag, "t";
- $C_{NOx,m,g,d,t}$ is the ozone contribution from EGU emissions of NO_X from tag, "t"; and
- $S_{t,i,y}$ is the ozone scaling ratio for tag, "t", scenario, "i", and year, "y".

Scaling ratios were applied to create air quality surfaces for $PM_{2.5}$ species using equation (10) (for sulfate, nitrate, EC or crustal material) or using equation (11) (for OA):

$$PM_{s,g,d,i,y} = C_{s,g,d,BC} + C_{s,g,d,int} + C_{s,g,d,bio} + C_{s,g,d,fires} + C_{s,g,d,USanthro} + C_{s,g,d,y,EGUret} + \sum_{t=1}^{T} C_{s,g,d,t} S_{s,t,i,y} \quad \text{(Eq-10)}$$

$$
\begin{aligned}
OA_{g,d,i,y} = C_{POA,g,d,BC} + C_{POA,g,d,int} + C_{POA,g,d,bio} + C_{POA,g,d,fires} \\
+ C_{POA,g,d,USanthro} + C_{POA,g,d,y,EGUret} + SOA_{g,d} \\
+ \sum_{t=1}^{T} C_{POA,g,d,t} S_{pri,t,i,y}
\end{aligned}
\quad \text{(Eq-11)}
$$

where:

- $PM_{s,g,d,i,y}$ is the estimated concentration for species, "s" (sulfate, nitrate, EC, or crustal material), grid-cell, "g", day, "d", scenario, "i", and year, "y";
- $C_{s,g,d,BC}$ is the species contribution from the modeled boundary inflow;
- $C_{s,g,d,int}$ is the species contribution from international emissions within the model domain;
- $C_{s,g,d,bio}$ is the species contribution from biogenic emissions;
- $C_{s,g,d,fires}$ is the species contribution from fires;
- $C_{s,g,d,USanthro}$ is the species contribution from U.S. anthropogenic sources other than EGUs;
- $C_{s,g,d,y,EGUret}$ is the species contribution from retiring EGUs after year, "y" (this term is equal to 0 in 2030 and 2035);
- $C_{s,g,d,t}$ is the species contribution from EGU emissions from tag, "t"; and
- $S_{s,t,i,y}$ is the scaling ratio for species, "s", tag, "t", scenario, "i", and year, "y".

Similarly, for Equation (11):

- $OA_{g,d,i,y}$ is the estimated OA concentration for grid-cell, "g", day, "d", scenario, "i", and year, "y";
- Each of the contribution terms refers to the contribution to primary OA (POA); and

- $SOA_{g,d}$ represents the modeled secondary organic aerosol concentration for gird-cell, “g”, and day, “d”, which does not change among scenarios

The scaling methodology described above treats air quality changes from the tagged sources as linear and additive. It therefore does not account for nonlinear atmospheric chemistry and also doesn’t account for non-linear interactions between emissions of different pollutants and between emissions from different tagged sources. This is consistent with how air quality estimations have been treated in past regulatory analyses (EPA, 2015). We note that air quality is calculated in the same manner for the baseline and the illustrative policy scenario, so any uncertainty associated with these assumptions is carried through both sets of scenarios in the same manner and is thus not expected to impact the air quality differences between scenarios. In addition, emissions changes between scenarios are relatively small compared to 2023 totals. Previous studies have shown that air pollutant concentrations generally respond linearly to small emissions changes of up to 30 percent (Dunker et al., 2002; Cohan et al., 2005; Napelenok et al., 2006; Koo et al., 2007; Zavala et al., 2009; Cohan and Napelenok, 2011) and therefore it is reasonable to expect that the differences between the baseline and the illustrative policy scenario can be adequately represented using this methodology.

We note that there is somewhat larger uncertainty in the estimations of absolute $PM_{2.5}$ and ozone concentrations associated with each of the scenarios due to fact that the emissions in the scenarios are quite different from the 2023 emissions for some tagged source categories as shown in Table 8-5 through Table 8-8. For example, in Table 8-6 the scaling ratio for sulfate impacts of coal EGU’s in Louisiana for the 2035 baseline is 0.30 indicating that emissions of SO_2 for this source category decreased by 70 percent compared to the 2023 modeled year, although the net change in emissions when accounting for all sources will be much lower. The assumption of linearity in sulfate impacts to this relatively large change in emissions adds uncertainty to the total predicted sulfate concentrations. However, the 2035 illustrative policy scenario had a scaling ratio of 0.31 which are relatively close to the baseline. Consequently, the linear response assumption should not drastically impact the estimates of changes in sulfate concentrations due to emissions changes from Louisiana coal EGU’s between scenarios. In addition, the absolute concentrations do not represent a single year of predicted air pollution but rather a combination of emissions expected in 2023 for all source other than EGUs and emissions expected in 2025, 2030, or 2035 from EGU sources. This adds uncertainty to what is represented by the absolute air pollution predictions but not to the differences in air quality between the baseline and illustrative policy scenario within a single year.

Table 8-5 Primary $PM_{2.5}$ Scaling Ratios for EGU tags

	Baseline (Coal)			Policy (Coal)			Baseline (Non-Coal)			Policy (Non-Coal)		
State	2025	2030	2035	2025	2030	2035	2025	2030	2035	2025	2030	2035
AL	0.45	0.53	0.47	0.45	0.54	0.47	0.48	0.49	0.51	0.48	0.48	0.51
AZ	0.34	0.31	0.28	0.34	0.31	0.27	0.71	0.84	0.89	0.71	0.83	0.89
AR	0.50	0.48	0.41	0.50	0.47	0.41	1.89	1.98	2.04	1.89	1.97	2.03
CA	1.00	1.00	1.00	1.00	1.00	1.00	0.34	0.20	0.19	0.34	0.20	0.19
CO	1.11	1.00	0.94	1.09	0.98	0.93	0.52	0.68	0.76	0.52	0.68	0.76
CT+RI	0.00	0.00	0.00	0.00	0.00	0.00	0.32	0.27	0.27	0.32	0.27	0.27
DE+NJ	0.00	0.00	0.00	0.00	0.00	0.00	0.74	0.76	0.78	0.73	0.75	0.78
FL	0.44	0.47	0.51	0.47	0.48	0.51	0.44	0.45	0.47	0.44	0.45	0.47
GA	0.46	0.49	0.47	0.47	0.50	0.47	1.44	1.50	1.50	1.44	1.49	1.49
ID + OR +WA	N/A	N/A	N/A	N/A	N/A	N/A	0.53	0.54	0.55	0.54	0.55	0.55
IL	0.77	0.77	0.72	0.73	0.74	0.69	0.86	1.07	1.21	0.84	1.03	1.21
IN	0.62	0.63	0.56	0.61	0.62	0.57	1.08	1.13	1.50	1.08	1.11	1.44
IA	0.95	0.97	0.92	0.97	0.96	0.92	1.28	1.45	1.70	1.28	1.46	1.70
KS	0.93	0.87	0.77	0.93	0.86	0.77	0.45	0.42	0.72	0.45	0.42	0.72
KY	0.26	0.25	0.21	0.26	0.24	0.21	3.49	4.39	5.27	3.43	4.49	5.38
LA	0.19	0.25	0.26	0.19	0.25	0.27	0.85	0.86	0.99	0.85	0.86	0.99
ME+MA+ NH+VT	0.00	0.00	0.00	0.00	0.00	0.00	0.14	0.01	0.01	0.02	0.01	0.01
MD	0.14	0.05	0.00	0.13	0.05	0.00	3.05	3.11	3.26	3.07	3.12	3.27
MI	0.95	0.96	0.84	0.94	0.96	0.84	1.15	1.17	1.62	1.15	1.16	1.62
MN	1.29	0.98	0.94	1.29	1.02	0.94	1.22	1.68	2.01	1.13	1.61	1.99
MS	0.22	0.22	0.20	0.21	0.21	0.21	0.93	1.00	1.01	0.93	1.00	0.99
MO	1.01	0.97	0.93	1.00	0.97	0.92	1.56	1.63	1.95	1.49	1.60	1.90
MT	1.04	1.04	1.04	1.02	1.02	1.02	0.03	0.04	0.05	0.03	0.04	0.05
NE	1.01	1.00	0.99	0.99	0.99	0.98	0.94	1.01	0.95	0.95	1.01	0.96
NV	0.80	0.44	0.38	0.79	0.42	0.37	0.90	1.02	1.09	0.90	1.02	1.09
NM	0.51	0.48	0.44	0.51	0.47	0.44	0.30	0.27	0.27	0.29	0.27	0.27
NY	0.00	0.00	0.00	0.00	0.00	0.00	0.72	0.68	0.70	0.72	0.68	0.69
NC	0.49	0.39	0.27	0.48	0.39	0.25	1.77	2.03	2.30	1.75	2.02	2.34
ND+SD	0.90	0.91	0.89	0.88	0.89	0.87	1.77	2.00	2.37	1.54	1.98	2.37
OH	0.76	0.73	0.58	0.75	0.72	0.55	2.15	2.98	3.19	2.32	2.96	3.18
OK	0.48	0.40	0.34	0.49	0.43	0.35	1.01	1.09	1.35	0.98	1.07	1.35
PA	0.29	0.24	0.19	0.29	0.21	0.19	1.46	1.45	1.58	1.45	1.45	1.58
SC	0.73	0.62	0.52	0.73	0.63	0.52	0.92	1.26	1.51	0.92	1.24	1.50
TN	0.42	0.38	0.33	0.35	0.31	0.29	2.36	2.39	3.03	2.37	2.41	2.99

State	Baseline (Coal)			Policy (Coal)			Baseline (Non-Coal)			Policy (Non-Coal)		
	2025	2030	2035	2025	2030	2035	2025	2030	2035	2025	2030	2035
TX	1.13	1.07	1.01	1.14	1.06	1.00	0.80	0.80	0.89	0.80	0.80	0.89
UT	0.64	0.64	0.57	0.63	0.63	0.57	0.47	0.52	0.62	0.48	0.52	0.63
VA	0.17	0.15	0.05	0.17	0.14	0.04	0.99	1.04	1.19	0.99	1.05	1.20
WV	0.70	0.67	0.43	0.70	0.66	0.42	1.00	2.40	22.11	1.00	4.38	22.88
WI	0.58	0.59	0.53	0.57	0.58	0.53	2.27	2.30	2.38	2.26	2.30	2.38
WY	0.95	0.93	0.91	0.93	0.92	0.90	0.37	4.62	4.53	0.37	4.45	4.53
Tribal	0.28	0.27	0.24	0.28	0.26	0.24	16.31	17.75	18.88	16.13	17.67	18.89

Table 8-6 Sulfate Scaling Ratios for EGU tags

State	Baseline (Coal)			Policy (Coal)			Baseline (Non-Coal)			Policy (Non-Coal)		
	2025	2030	2035	2025	2030	2035	2025	2030	2035	2025	2030	2035
AL	0.75	0.86	0.75	0.75	0.85	0.75	0.00	0.00	0.00	0.00	0.00	0.00
AZ	1.16	1.12	0.96	1.16	1.13	0.94	0.00	0.00	0.00	0.00	0.00	0.00
AR	2.19	2.07	1.72	2.19	2.04	1.74	0.00	0.00	0.00	0.00	0.00	0.00
CA	0.98	0.00	0.00	0.98	0.00	0.00	0.17	0.01	0.01	0.17	0.01	0.01
CO	1.00	0.93	0.88	0.98	0.92	0.86	0.00	0.00	0.00	0.00	0.00	0.00
CT+RI	0.00	0.00	0.00	0.00	0.00	0.00	1.96	1.96	1.96	1.96	1.96	1.96
DE+NJ	0.00	0.00	0.00	0.00	0.00	0.00	2.67	2.67	2.67	2.67	2.67	2.67
FL	0.73	0.82	0.88	0.81	0.83	0.88	0.68	0.68	0.67	0.68	0.68	0.67
GA	1.83	1.68	1.58	1.82	1.70	1.61	0.04	0.05	0.05	0.02	0.05	0.05
ID + OR +WA	N/A	N/A	N/A	N/A	N/A	N/A	0.07	0.07	0.07	0.07	0.07	0.07
IL	0.77	0.78	0.73	0.75	0.75	0.70	0.00	0.00	0.00	0.00	0.00	0.00
IN	0.91	0.88	0.81	0.90	0.87	0.82	0.20	0.20	0.20	0.20	0.20	0.20
IA	0.49	0.49	0.47	0.50	0.49	0.47	0.00	0.00	0.00	0.00	0.00	0.00
KS	2.34	2.18	1.99	2.34	2.16	1.99	0.00	0.00	0.00	0.00	0.00	0.00
KY	0.26	0.27	0.23	0.26	0.27	0.23	0.03	0.03	0.02	0.03	0.02	0.02
LA	0.27	0.29	0.30	0.27	0.28	0.31	0.06	0.06	0.06	0.06	0.06	0.06
ME+MA+ NH+VT	0.00	0.00	0.00	0.00	0.00	0.00	0.60	0.54	0.55	0.59	0.54	0.55
MD	0.07	0.03	0.00	0.07	0.03	0.00	0.45	0.45	0.45	0.45	0.45	0.45
MI	0.97	1.00	0.78	0.97	1.00	0.81	0.06	0.06	0.06	0.06	0.06	0.06
MN	1.39	1.33	1.31	1.40	1.35	1.32	0.36	0.36	0.36	0.36	0.36	0.36
MS	0.66	0.67	0.62	0.65	0.66	0.65	0.00	0.00	0.00	0.00	0.00	0.00
MO	1.23	1.28	1.27	1.22	1.28	1.26	0.00	0.00	0.00	0.00	0.00	0.00
MT	0.52	0.61	0.61	0.51	0.60	0.60	0.00	0.00	0.00	0.00	0.00	0.00
NE	0.78	0.78	0.96	0.77	0.77	0.95	0.00	0.00	0.00	0.00	0.00	0.00
NV	13.26	2.84	2.43	12.95	2.73	2.41	0.00	0.00	0.00	0.00	0.00	0.00
NM	1.41	1.31	1.23	1.40	1.30	1.22	0.00	0.00	0.00	0.00	0.00	0.00
NY	0.01	0.01	0.01	0.01	0.01	0.01	1.92	0.64	0.64	1.92	0.64	0.64

State	Baseline (Coal)			Policy (Coal)			Baseline (Non-Coal)			Policy (Non-Coal)		
	2025	2030	2035	2025	2030	2035	2025	2030	2035	2025	2030	2035
NC	0.56	0.47	0.35	0.56	0.47	0.33	0.01	0.01	0.01	0.01	0.01	0.01
ND+SD	0.62	0.64	0.63	0.60	0.62	0.62	0.00	0.00	0.00	0.00	0.00	0.00
OH	0.68	0.69	0.49	0.67	0.70	0.48	0.08	0.08	0.08	0.08	0.08	0.08
OK	1.22	0.97	0.85	1.25	1.01	0.84	0.00	0.00	0.00	0.00	0.00	0.00
PA	0.15	0.12	0.09	0.15	0.11	0.09	0.04	0.04	0.04	0.04	0.04	0.04
SC	2.70	2.13	1.78	2.68	2.15	1.77	0.01	0.01	0.01	0.01	0.01	0.01
TN	0.45	0.34	0.28	0.40	0.29	0.26	0.00	0.00	0.00	0.00	0.00	0.00
TX	0.92	0.86	0.84	0.93	0.86	0.83	0.04	0.04	0.04	0.04	0.04	0.04
UT	1.09	1.24	1.34	1.07	1.23	1.32	0.00	0.00	0.00	0.00	0.00	0.00
VA	0.60	0.56	0.19	0.60	0.55	0.14	0.20	0.20	0.20	0.20	0.20	0.20
WV	0.88	0.85	0.55	0.87	0.84	0.54	0.00	0.00	0.00	0.00	0.00	0.00
WI	0.92	0.93	0.82	0.91	0.92	0.82	0.00	0.00	0.00	0.00	0.00	0.00
WY	0.64	0.56	0.68	0.61	0.55	0.67	0.00	0.00	0.00	0.00	0.00	0.00
Tribal	1.26	1.22	1.14	1.25	1.22	1.13	0.00	0.00	0.00	0.00	0.00	0.00

Table 8-7 Nitrate Scaling Ratios for EGU tags

State	Baseline (Coal)			Policy (Coal)			Baseline (Non-Coal)			Policy (Non-Coal)		
	2025	2030	2035	2025	2030	2035	2025	2030	2035	2025	2030	2035
AL	0.35	0.41	0.37	0.35	0.41	0.37	0.58	0.69	0.92	0.58	0.68	0.97
AZ	0.40	0.38	0.31	0.39	0.38	0.30	0.50	0.59	0.61	0.50	0.59	0.62
AR	1.57	1.41	1.16	1.57	1.39	1.17	0.78	0.82	0.90	0.77	0.82	0.90
CA	0.12	0.00	0.00	0.12	0.00	0.00	0.92	0.32	0.34	0.92	0.32	0.34
CO	0.87	0.83	0.79	0.86	0.82	0.77	0.33	0.53	0.54	0.33	0.53	0.53
CT+RI	0.00	0.00	0.00	0.00	0.00	0.00	1.13	1.10	1.10	1.13	1.10	1.10
DE+NJ	0.00	0.00	0.00	0.00	0.00	0.00	1.29	1.30	1.37	1.29	1.30	1.37
FL	0.52	0.54	0.59	0.55	0.57	0.59	1.00	1.02	0.99	0.99	1.01	0.99
GA	0.52	0.55	0.51	0.53	0.57	0.53	0.75	0.90	0.94	0.74	0.89	0.94
ID + OR +WA	N/A	N/A	N/A	N/A	N/A	N/A	0.49	0.57	0.54	0.50	0.57	0.54
IL	0.99	1.00	0.93	0.93	0.95	0.88	0.69	0.81	0.88	0.68	0.79	0.88
IN	0.78	0.79	0.71	0.76	0.77	0.71	0.83	0.84	1.04	0.82	0.82	1.01
IA	1.25	1.26	1.19	1.28	1.26	1.19	0.97	0.99	1.22	0.94	0.99	1.21
KS	1.17	1.10	0.97	1.19	1.09	0.98	1.54	1.49	1.28	1.53	1.50	1.28
KY	0.39	0.36	0.31	0.40	0.36	0.31	1.44	1.48	1.60	1.41	1.43	1.60
LA	0.30	0.31	0.33	0.29	0.31	0.33	0.40	0.36	0.34	0.40	0.36	0.34
ME+MA+ NH+VT	0.00	0.00	0.00	0.00	0.00	0.00	0.87	0.71	0.73	0.80	0.71	0.73
MD	0.10	0.04	0.00	0.10	0.04	0.00	1.21	1.23	1.22	1.21	1.22	1.22
MI	1.19	1.22	1.01	1.19	1.22	1.03	1.06	1.09	1.15	1.06	1.07	1.15
MN	1.28	0.97	0.93	1.28	1.00	0.94	0.65	0.70	0.86	0.64	0.70	0.84
MS	0.24	0.24	0.22	0.23	0.23	0.23	0.42	0.47	0.45	0.42	0.46	0.44

State	Baseline (Coal) 2025	2030	2035	Policy (Coal) 2025	2030	2035	Baseline (Non-Coal) 2025	2030	2035	Policy (Non-Coal) 2025	2030	2035
MO	1.16	1.08	1.03	1.15	1.09	1.02	0.56	0.59	0.88	0.54	0.59	0.86
MT	0.95	0.95	0.95	0.93	0.93	0.93	0.01	0.02	0.03	0.01	0.02	0.03
NE	1.13	1.12	1.11	1.11	1.11	1.09	1.01	0.98	0.93	0.99	0.98	0.93
NV	4.91	0.99	0.85	4.80	0.95	0.84	0.89	1.03	1.10	0.89	1.04	1.11
NM	0.76	0.67	0.54	0.74	0.66	0.53	0.41	0.24	0.18	0.41	0.24	0.18
NY	0.00	0.00	0.00	0.00	0.00	0.00	0.95	0.92	0.93	0.95	0.92	0.92
NC	0.87	0.69	0.47	0.86	0.67	0.42	0.86	0.83	0.84	0.84	0.83	0.88
ND+SD	0.77	0.78	0.75	0.76	0.76	0.74	0.45	0.53	0.62	0.46	0.53	0.62
OH	1.04	0.98	0.76	1.03	0.98	0.73	1.55	1.87	1.77	1.61	1.85	1.75
OK	1.84	1.62	1.38	1.94	1.71	1.41	0.64	0.67	0.74	0.62	0.65	0.74
PA	0.38	0.30	0.24	0.37	0.27	0.24	1.25	1.12	1.24	1.22	1.11	1.24
SC	1.12	0.99	0.81	1.12	1.00	0.81	0.67	0.71	0.77	0.67	0.69	0.76
TN	0.48	0.45	0.40	0.36	0.32	0.31	0.80	0.94	0.99	0.84	1.00	0.97
TX	1.12	1.05	0.98	1.12	1.04	0.96	0.85	0.84	0.90	0.85	0.83	0.90
UT	1.07	1.07	0.96	1.07	1.07	0.95	0.38	0.42	0.51	0.39	0.42	0.51
VA	0.16	0.13	0.05	0.16	0.13	0.03	0.96	1.03	1.09	0.96	1.03	1.09
WV	0.95	0.89	0.59	0.94	0.88	0.58	0.16	0.26	1.02	0.16	0.33	1.05
WI	0.63	0.65	0.57	0.62	0.64	0.57	0.78	0.82	0.88	0.77	0.82	0.88
WY	0.91	0.84	0.83	0.88	0.82	0.81	0.05	0.64	0.62	0.05	0.61	0.62
Tribal	0.60	0.58	0.50	0.59	0.57	0.49	13.90	15.17	15.36	13.87	15.10	15.46

Table 8-8 Ozone Scaling Ratios for EGU tags

State	Baseline (Coal) 2025	2030	2035	Policy (Coal) 2025	2030	2035	Baseline (Non-Coal) 2025	2030	2035	Policy (Non-Coal) 2025	2030	2035
AL	0.45	0.60	0.63	0.44	0.60	0.62	0.77	0.78	0.88	0.77	0.76	0.98
AZ	0.41	0.43	0.45	0.39	0.43	0.44	0.43	0.50	0.49	0.43	0.50	0.48
AR	1.44	1.44	1.45	1.44	1.44	1.45	0.65	0.63	0.60	0.65	0.63	0.60
CA	0.11	0.00	0.00	0.11	0.00	0.00	0.81	0.31	0.34	0.79	0.31	0.34
CO	0.89	0.85	0.85	0.88	0.84	0.84	0.43	0.66	0.54	0.43	0.67	0.52
CT+RI	0.00	0.00	0.00	0.00	0.00	0.00	1.11	1.09	1.12	1.11	1.09	1.12
DE+NJ	0.00	0.00	0.00	0.00	0.00	0.00	1.14	1.11	1.11	1.14	1.11	1.11
FL	0.70	0.79	1.03	0.72	0.84	1.04	0.96	0.95	0.89	0.94	0.95	0.89
GA	0.90	1.01	1.13	0.93	1.05	1.20	0.66	0.85	0.71	0.65	0.85	0.71
ID + OR +WA	N/A	N/A	N/A	N/A	N/A	N/A	0.39	0.42	0.41	0.39	0.42	0.40
IL	0.96	1.00	0.96	0.91	0.94	0.90	0.88	0.91	1.00	0.86	0.85	1.00
IN	0.91	0.93	0.81	0.88	0.92	0.82	1.03	0.98	1.10	1.03	0.94	1.06
IA	1.12	1.13	1.13	1.13	1.14	1.12	1.24	1.15	1.52	1.19	1.17	1.50
KS	1.17	1.19	1.19	1.14	1.16	1.16	2.19	2.06	1.76	2.18	2.09	1.76

State	Baseline (Coal)			Policy (Coal)			Baseline (Non-Coal)			Policy (Non-Coal)		
	2025	2030	2035	2025	2030	2035	2025	2030	2035	2025	2030	2035
KY	0.45	0.46	0.45	0.49	0.45	0.45	1.60	1.36	1.24	1.55	1.31	1.23
LA	0.41	0.45	0.49	0.40	0.44	0.51	0.45	0.40	0.28	0.45	0.40	0.28
ME+MA+ NH+VT	0.00	0.00	0.00	0.00	0.00	0.00	0.88	0.74	0.79	0.81	0.74	0.79
MD	0.13	0.00	0.00	0.13	0.00	0.00	1.08	1.09	1.05	1.08	1.08	1.05
MI	1.10	1.17	1.13	1.10	1.17	1.14	1.16	1.10	1.16	1.16	1.10	1.16
MN	1.28	0.99	0.99	1.26	1.02	0.98	0.75	0.79	1.11	0.73	0.78	1.06
MS	0.29	0.30	0.30	0.29	0.29	0.29	0.40	0.40	0.33	0.41	0.40	0.32
MO	1.12	1.15	1.14	1.11	1.17	1.12	0.60	0.61	0.66	0.60	0.60	0.64
MT	1.07	1.07	1.07	1.05	1.05	1.05	0.03	0.05	0.08	0.03	0.05	0.08
NE	1.14	1.14	1.14	1.12	1.12	1.12	1.07	1.03	0.97	1.05	1.02	0.97
NV	0.80	0.91	0.91	0.80	0.91	0.91	0.70	0.76	1.00	0.70	0.76	1.01
NM	0.84	0.84	0.84	0.82	0.82	0.82	0.52	0.43	0.26	0.52	0.42	0.26
NY	0.00	0.00	0.00	0.00	0.00	0.00	0.87	0.85	0.84	0.88	0.85	0.84
NC	0.92	0.78	0.60	0.90	0.73	0.50	1.10	0.95	0.84	1.06	0.95	0.91
ND+SD	0.81	0.84	0.82	0.79	0.82	0.81	0.65	0.75	0.87	0.72	0.74	0.87
OH	1.00	0.95	0.82	0.99	0.95	0.81	1.57	1.73	1.67	1.61	1.72	1.63
OK	2.27	2.24	2.14	2.28	2.19	2.14	0.83	0.77	0.73	0.80	0.79	0.72
PA	0.39	0.37	0.34	0.38	0.38	0.34	1.04	0.88	0.90	1.01	0.88	0.89
SC	1.09	1.11	1.04	1.09	1.12	1.04	0.81	0.77	0.82	0.81	0.74	0.81
TN	0.51	0.51	0.51	0.37	0.37	0.41	0.69	0.75	0.69	0.78	0.78	0.69
TX	1.07	1.19	1.22	1.07	1.18	1.20	0.95	0.88	0.86	0.94	0.87	0.86
UT	1.11	1.11	1.11	1.11	1.11	1.11	0.19	0.21	0.23	0.20	0.22	0.23
VA	0.17	0.17	0.06	0.17	0.17	0.04	0.92	0.93	0.94	0.92	0.93	0.94
WV	1.10	1.10	0.93	1.09	1.09	0.92	0.25	0.28	0.95	0.25	0.33	0.98
WI	0.52	0.61	0.54	0.54	0.60	0.54	0.70	0.76	0.84	0.70	0.76	0.83
WY	0.89	0.83	0.83	0.86	0.83	0.82	0.07	0.12	0.07	0.07	0.09	0.07
Tribal	0.63	0.63	0.64	0.62	0.63	0.63	16.21	17.84	16.67	16.21	17.74	16.54

8.4 Creating Fused Fields Based on Observations and Model Surfaces

In Chapter 4 we describe steps taken to estimate $PM_{2.5}$ and ozone gridded surfaces associated with the baseline and the illustrative policy scenario for every year. For $PM_{2.5}$, steps (4) - (8) (Chapter 4) describe how daily gridded $PM_{2.5}$ species were processed into annual average surfaces which combine observed values with model predictions using the enhanced Veronoi Neighbor Average (eVNA) method (Gold et al., 1997; US EPA, 2007; Ding et al., 2015). These steps were performed using EPA's software package, Software for the Modeled

Attainment Test – Community Edition (SMAT-CE)[19] and have been previously documented both in the user's guide for the predecessor software (Abt, 2014) and in EPA's modeling guidance document (U.S. EPA, 2014b). As explained in Chapter 4, we first create a 2011 eVNA surface for each PM component species. To create the 2011 eVNA surface, SMAT-CE first calculates quarterly average values (January-March; April-June; July-September; October-December) for each $PM_{2.5}$ component species at each monitoring site with available measured data. For this calculation we used 3 years of monitoring data (2010-2012)[20]. SMAT-CE then creates an interpolated field of the quarterly-average observed data for each $PM_{2.5}$ component species using inverse distance squared weighting resulting in a separate 3-year average interpolated observed field for each $PM_{2.5}$ species and each quarter. The interpolated observed fields are then adjusted to match the spatial gradients from the modeled data. These two steps can be calculated using Equation (12):

$$eVNA_{g,s,q,2011} = \sum Weight_x Monitor_{x,s,q,2010-2012} \frac{Model_{g,s,q,2011}}{Model_{x,s,q,2011}} \qquad \text{(Eq-12)}$$

Where:

- $eVNA_{g,s,q,current}$ is the gradient adjusted quarterly-average eVNA value at grid-cell, g, for PM component species, s, during quarter, q for the year 2011;
- $Weight_x$ is the inverse distance weight for monitor x at the location of grid-cell, g;
- $Monitor_{x,s,q,2010-2012}$ is the 3-year (2010-2012) average of the quarterly monitored concentration for species, s, at monitor, x, during quarter, q;
- $Model_{g,s,q,2011}$ is the 2011 modeled quarterly-average concentrations of species, s, at grid cell, g, during quarter, q; and

[19] Software download and documentation available at https://www.epa.gov/scram/photochemical-modeling-tools
[20] Three years of ambient data is used to provide a more representative picture of air pollution concentrations.

- $Model_{x,s,q,2011}$ is the 2011 modeled quarterly-average concentration of species, s, at the location of monitor, x, during quarter q.

The 2011 eVNA field serves as the starting point for future-year projections. As described in Chapter 4, to create a gridded future-year eVNA surfaces for the baseline and illustrative policy scenario for 2025/2030/2035, we take the ratio of the modeled future year[21] quarterly average concentration to the modeled 2011 concentration in each grid cell and multiply that by the corresponding 2011 eVNA quarterly $PM_{2.5}$ component species value in that grid cell (Equation 13).

$$eVNA_{g,s,q,future} = \left(eVNA_{g,s,q,2011}\right) \times \frac{Model_{g,s,q,future}}{Model_{g,s,q,2011}} \qquad \text{(Eq-13)}$$

This results in a gridded future-year projection which accounts for adjustments to match observations in the 2011 modeled data.

Finally, particulate ammonium concentrations are impacted both by emissions of precursor ammonia gas as well as ambient concentrations of particulate sulfate and nitrate. Because of uncertainties in ammonium speciation measurements combined with sparse ammonium measurements in rural areas, the SMAT-CE default is to calculate ammonium values using the degree of sulfate neutralization (i.e., the relative molar mass of ammonium to sulfate with the assumption that all nitrate is fully neutralized). Degree of neutralization values are mainly available in urban areas while sulfate measurements are available in both urban and rural areas. Ammonium is thus calculated by multiplying the interpolated degree of neutralization value by the interpolated sulfate value at each grid-cell location which allows the ammonium fields to be informed by rural sulfate measurements in locations where no rural ammonium measurements are available. The degree of neutralization is not permitted to exceed the maximum theoretical molar ratio of 2:1 for ammonium:sulfate. When creating the future year surface for particulate ammonium, we use the default SMAT-CE assumption that the degree of neutralization for the aerosol remains at 2011 levels.

[21] In this analysis the "future year" modeled concentration is the result of Equations 9, 10 or 11 that represents either the baseline or the illustrative policy scenario for 2025, 2030, or 2035.

A similar method for creating future-year eVNA surfaces is followed for the two ozone metrics with a few key differences. First, while $PM_{2.5}$ is split into quarterly averages and then averaged up to an annual value, we look at ozone as a summer-season average using definitions that match metrics from epidemiology studies (May-Sep for MDA8 and Apr-Oct for MDA1). The other main difference in the SMAT-CE calculation for ozone is that the spatial interpolation of observations uses an inverse distance weighting rather than an inverse distance squared weighting. This results in interpolated observational fields that better replicate the more gradual spatial gradients observed in ozone compared to $PM_{2.5}$.

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United States Environmental Protection Agency	Office of Air Quality Planning and Standards Health and Environmental Impacts Division Research Triangle Park, NC	Publication No. EPA-452/R-19-003 June 2019