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

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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

U.S. Environmental Protection Agency
Office of Air Quality Planning and Standards
Health and Environmental Impact Division
Research Triangle Park, NC

CONTACT INFORMATION

This document has been prepared by staff from the Office of Air Quality Planning and Standards, the Office of Atmospheric Programs, and the Office of Policy of the U.S. Environmental Protection Agency. Questions related to this document should be addressed to Brian Keaveny, U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina 27711 (email: keaveny.brian@epa.gov).

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EXECUTIVE SUMMARY

ES.1 Introduction

With this notice, the Environmental Protection Agency (EPA) is proposing three distinct actions, including Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units (EGUs). First, EPA is proposing to replace the Clean Power Plan (CPP) with revised emissions guidelines (the Affordable Clean Energy (ACE) rule) for states to follow in developing implementation plans to reduce greenhouse gas emission from certain EGUs. In the proposed emissions guidelines (UUUUa), consistent with the interpretation described in the proposed repeal of the CPP, the Agency is proposing to determine that heat rate improvement (HRI) measures are the best system of emission reduction (BSER) for existing coal-fired EGUs. Second, EPA is proposing new regulations that provide direction to both EPA and the states on the implementation of emission guidelines. The new proposed implementing regulations would apply to this action and any future emission guideline issued under section 111(d) of the Clean Air Act (CAA). Third, the Agency is proposing revisions to the New Source Review (NSR) program that will help prevent NSR from being a barrier to the implementation of efficiency projects at EGUs.

This proposed 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 a full benefit cost analysis of four illustrative scenarios. The four illustrative scenarios include a scenario modeling the full repeal of the CPP, which we term a No CPP case, and three replacement policy scenarios modeling heat rate improvements (HRI) at coal-fired EGUs. Throughout this RIA, these three illustrative policy scenarios are compared against a base case, which includes the CPP. By analyzing against the existing CPP, the reader can understand the combined impact of a repeal and replacement. Inclusion of a No CPP case allows for an understanding of the repeal alone and allows the reader to evaluate the impact of the policy cases against a No CPP scenario. This RIA assumes a mass-based implementation of the CPP for existing affected sources, and does not assume interstate trading. The three illustrative policy scenarios represent potential outcomes of state determinations of standards of performance, and compliance with those standards by affected coal-fired EGUs.

The analysis relies on EPA's Power Sector Modeling Platform v6 using the Integrated Planning Model (IPM). This accounts for changes in the power sector since promulgation of the CPP in 2015, and projects our best understanding of important technological and economic trends into the future. This RIA also updates the analysis in the October 2017 RIA for the proposed repeal of the CPP, by updating, among other elements of the analysis, the expected future economic conditions affecting the electricity sector in both the base case, which includes the CPP, and the No CPP scenario.

Three of the illustrative scenarios model different levels and costs of HRIs applied uniformly at all affected coal-fired EGUs in the contiguous U.S. beginning in 2025. EPA has identified the BSER to be HRI. In final Emission Guidelines, EPA will provide states with a list of candidate HRI technologies that must be evaluated when establishing standards of performance. Each of these illustrative scenarios assumes that the affected sources are no longer subject to the state plan requirements of the CPP (i.e., the mass-based requirements assumed for CPP implementation in the base case for this RIA). 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. 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 many factors into consideration – including the remaining useful life of the affected source – when applying the standards of performance. Therefore, any analysis of the proposed rule must be highly illustrative. However, 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. To avoid the impression that EPA can sufficiently distinguish likely standards of performance across individual affected units and their compliance strategies, this analysis assumes different HRI levels and costs are applied uniformly to affected coal-fired EGUs under each of three illustrative policy scenarios:

- **2 Percent HRI at $50/kW**: This illustrative scenario represents a policy case that reflects modest improvements in HRI absent any revisions to NSR requirements. For many years, industry has indicated to the Agency that many sources have not implemented certain HRI projects because the burdensome costs of NSR cause such projects to not be viable. Thus, absent NSR reform, HRI at affected units might be expected to be modest. Based on numerous studies and statistical analysis, the Agency believes that the HRI potential for coal-fired EGUs will, on average, range from one to three percent at a cost of $30 to $60 per kilowatt (kW) of EGU generating capacity. The Agency believes that this scenario (2 percent HRI at $50/kW) reasonably represents that range of HRI and cost.
- **4.5 Percent HRI at $50/kW**: This illustrative scenario represents a policy case that includes benefits from the proposed revisions to NSR, with the HRI modeled at a low cost. As mentioned earlier, the Agency is proposing revisions to the NSR program that will provide owners and operators of existing EGUs greater ability to make efficiency improvements without triggering provisions of NSR. This scenario is informative in that it represents the ability of all coal-fired EGUs to obtain greater improvements in heat rate because of NSR reform at the $50/kW cost identified earlier. EPA believes this higher heat rate improvement potential is possible because without NSR a greater number of units may have the opportunity to make cost effective heat rate improvements such as turbine upgrades that have the potential to offer greater heat rate improvement opportunities.
- **4.5 Percent HRI at $100/kW**: This illustrative scenario represents a policy case that includes the benefits from the proposed revisions to NSR, with the HRI modeled at a higher cost. This scenario is informative in that it represents the ability of a typical coal-fired EGUs to obtain greater improvements in heat rate because of NSR reform but at a much higher cost ($100/kW) than the $50/kW cost identified earlier. Particularly for lower capacity units or those with limited remaining useful life, this could ultimately translate into HRI projects with higher costs.

Combined, the 4.5 percent HRI at $50/kW scenario and the 4.5 percent HRI at $100/kW scenario represent a range of potential costs for the proposed policy option that couples HRI with NSR reform. Modeling this at $50/kW and $100/kW provides a sensitivity analysis on the cost of the proposed policy including NSR reform. The $50/kW cost represents an optimistic bounding where NSR reform unleashes significant new opportunity for low-cost heat rate improvements. The $100/kW cost scenario represents higher costs. Additional information describing these illustrative scenarios is located in Chapter 1.

The Agency understands that there may be interest in comparing the three illustrative policy scenarios against an alternative baseline that does not include the CPP. For those interested in comparing the potential impacts of policy scenarios in a world without the CPP, results from the three illustrative policy scenarios may be compared against an alternative baseline results from the illustrative No CPP case, which we term the No CPP alternative baseline. The presentation of an alternative baseline is consistent with Circular A-4, which states, "When more than one baseline is reasonable and the choice of baseline will significantly affect estimated benefits and costs, you should consider measuring benefits and costs against alternative baselines"[1] While these comparisons are not presented throughout the RIA, we provide information in this Executive Summary comparing the three illustrative policy scenarios to the No CPP alternative baseline. In addition, the full suite of model outputs and additional comparison tables are available in the docket.

We evaluate the potential regulatory impacts of the illustrative No CPP scenario and the three illustrative policy scenarios 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 beginning-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 2025-2037. The year 2025 is an approximation for when the standards of performance under the proposed 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.

This RIA builds upon the methodological changes contained in the Regulatory Impact Analysis for the Review of the Clean Power Plan: Proposal. In addition, EPA is currently seeking comment, through its Advanced Notice of Proposed Rulemaking on Increasing

[1] Office of Management and Budget (OMB), 2003, Circular A-4, https://www.whitehouse.gov/sites/whitehouse.gov/files/omb/circulars/A4/a-4.pdf

Consistency and Transparency in Considering Costs and Benefits in the Rulemaking Process (83 FR 27524), on a variety of related matters, including possible approaches for increasing consistency and transparency in considering costs and benefits in the rulemaking process.

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, for both baselines. Table ES-1 provides the present value (PV) and equivalent annualized value (EAV) of costs, benefits, and net benefits relative to the base case (which includes CPP) associated with the targeted pollutant, CO_2, over the timeframe of 2023-2037. Table ES-2 presents the same set of information, but relative to the No CPP alternative. In these two tables, negative costs indicate avoided costs, negative benefits indicate forgone benefits, and negative net benefits indicate forgone net benefits.

Table ES-1 Present Value and Equivalent Annualized Value of Compliance Costs, Climate Benefits, and Net Benefits Associated with Targeted Pollutant (CO_2), Relative to Base Case (CPP), 3 and 7 Percent Discount Rates, 2023-2037 (billions of 2016$)

	Costs		Domestic Climate Benefits		Net Benefits associated with the Targeted Pollutant (CO_2)	
	3%	7%	3%	7%	3%	7%
Present Value						
No CPP	(5.2)	(3.1)	(3.9)	(0.4)	1.2	2.7
2% HRI at $50/kW	(0.4)	(0.3)	(3.2)	(0.3)	(2.8)	(0.1)
4.5% HRI at $50/kW	(6.4)	(3.7)	(3.2)	(0.3)	3.2	3.4
4.5% HRI at $100/kW	3.0	1.7	(2.4)	(0.2)	(5.4)	(2.0)
Equivalent Annualized Value						
No CPP	(0.4)	(0.3)	(0.3)	(0.0)	0.1	0.3
2% HRI at $50/kW	(0.0)	(0.0)	(0.3)	(0.0)	(0.2)	(0.0)
4.5% HRI at $50/kW	(0.5)	(0.4)	(0.3)	(0.0)	0.3	0.4
4.5% HRI at $100/kW	0.3	0.2	(0.2)	(0.0)	(0.5)	(0.2)

Notes: Negative costs indicate avoided costs, negative benefits indicate forgone benefits, and negative net benefits indicate forgone net benefits. All estimates are rounded to one decimal point, 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.

Table ES-2 Present Value and Equivalent Annualized Value of Compliance Costs, Climate Benefits, and Net Benefits Associated with Targeted Pollutant (CO_2), Relative to the No CPP Alternative Baseline, 3 and 7 Percent Discount Rates, 2023-2037 (billions of 2016$)

	Costs		Domestic Climate Benefits		Net Benefits associated with the Targeted Pollutant (CO_2)	
	3%	7%	3%	7%	3%	7%
Present Value						
2% HRI at $50/kW	4.8	2.8	0.8	0.1	(4.1)	(2.8)
4.5% HRI at $50/kW	(1.2)	(0.6)	0.7	0.1	2.0	0.7
4.5% HRI at $100/kW	8.2	4.8	1.6	0.2	(6.6)	(4.7)
Equivalent Annualized Value						
2% HRI at $50/kW	0.4	0.3	0.1	0.0	(0.3)	(0.3)
4.5% HRI at $50/kW	(0.1)	(0.1)	0.1	0.0	0.2	0.1
4.5% HRI at $100/kW	0.7	0.5	0.1	0.0	(0.6)	(0.5)

Notes: Negative costs indicate avoided costs, negative benefits indicate forgone benefits, and negative net benefits indicate forgone net benefits. All estimates are rounded to one decimal point, 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 base case and illustrative scenarios, including the cost of monitoring, reporting, and recordkeeping (MR&R). In simple terms, these costs are an estimate of the increased power industry expenditures required to implement the HRI required by the proposed rule, minus the sectoral cost of complying with the CPP assumed in the base case. Table ES-3 presents the annualized compliance costs of the three illustrative policy scenarios and the illustrative No CPP scenario.[2] In this table, and throughout the RIA, negative costs indicate avoided costs relative to the base case (which includes the CPP), and positive costs indicate an increase in projected compliance costs, relative to the base case. As shown in Table ES-3, the Agency estimates that there are avoided costs under three out of the four illustrative scenarios base case (which includes the CPP). EPA uses the projection of private compliance costs as an

[2] 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.

estimate of the social cost, which is the appropriate metric for formal economic welfare analysis, of this proposal.

Table ES-3 Compliance Costs, Relative to Base Case (CPP) (billions of 2016$)

	No CPP	2% HRI at $50/kW	4.5% HRI at $50/kW	4.5% HRI at $100/kW
2025	(0.7)	0.0	(0.6)	0.5
2030	(0.7)	(0.2)	(1.0)	0.2
2035	(0.4)	0.1	(0.6)	0.5

Notes: Negative costs indicate that, on net, the illustrative scenario avoids costs relative to the base case with the CPP. Compliance costs equal the projected change in total power sector generating costs, plus the costs of monitoring, reporting, and recordkeeping.

As shown in Table ES-4, EPA estimates that there are avoided costs under one of the three illustrative scenarios relative to the No CPP alternative baseline.

Table ES-4 Compliance Costs, Relative to No CPP Alternative Baseline (billions of 2016$)

	2% HRI at $50/kW	4.5% HRI at $50/kW	4.5% HRI at $100/kW
2025	0.7	0.1	1.3
2030	0.5	(0.2)	0.9
2035	0.5	(0.2)	0.8

Notes: Negative costs indicate that, on net, the illustrative scenario reduces costs relative to the No CPP alternative baseline. Compliance costs equal the projected change in total power sector generating costs, plus the costs of monitoring, reporting, and recordkeeping.

Due to a number of changes in the electricity sector since the CPP was finalized, as documented in the October 2017 RIA conducted for the proposed CPP repeal and Chapter 3 of this RIA, the sector has become less carbon intensive over the past several years, and the trend is projected to continue. These changes and trends are reflected in the modeling used for this analysis. As such, achieving the emissions levels required under CPP requires less effort and expense, relative to a scenario without the CPP, and the estimated compliance costs are significantly lower than what was estimated in the final CPP RIA (U.S. EPA, 2015).

ES.4 Emissions Changes

Emissions are projected to be higher under the three illustrative policy scenarios and the illustrative No CPP scenario than under the base case, as the base case includes the CPP. Table ES-5 shows the projected CO_2 emissions impacts of each scenario, relative to the base case including the CPP.

Table ES-5 Projected CO_2 Emission Impacts, Relative to Base Case (CPP) Scenario

	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
No CPP	1,829	1,811	1,794	50	74	66	3%	4%	4%
Base Case (CPP)	1,780	1,737	1,728	--	--	--	--	--	--
2% HRI at $50/kW	1,816	1,798	1,783	37	61	55	2%	3%	3%
4.5% HRI at $50/kW	1,812	1,797	1,787	32	60	59	2%	3%	3%
4.5% HRI at $100/kW	1,799	1,785	1,772	20	47	44	1%	3%	3%

Table ES-6 shows the projected CO_2 emissions impacts of each scenario, relative to the No CPP alternative baseline.

Table ES-6 Projected CO_2 Emission Impacts, Relative to No CPP Alternative 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
No CPP	1,829	1,811	1,794	--	--	--	--	--	--
2% HRI at $50/kW	1,816	1,798	1,783	-13	-13	-11	-1%	-1%	-1%
4.5% HRI at $50/kW	1,812	1,797	1,787	-18	-14	-7	-1%	-1%	0%
4.5% HRI at $100/kW	1,799	1,785	1,772	-30	-27	-22	-2%	-1%	-1%

Table ES-7 shows projected emission increases relative to the base case for carbon dioxide (CO_2), sulfur dioxide (SO_2) and nitrogen oxides (NO_X) from the electricity sector.

Table ES-7 Projected CO_2, SO_2, and NO_X Electricity Sector Emission Increases, Relative to the Base Case (CPP) (2025-2035)

	CO_2 (million short tons)	SO_2 (thousand short tons)	NO_X (thousand short tons)
No CPP			
2025	50	36	32
2030	74	60	47
2035	66	44	43
2% HRI at $50/kW			
2025	37	35	24
2030	61	53	39
2035	55	34	39
4.5% HRI at $50/kW			
2025	32	40	21
2030	60	53	39
2035	59	43	43
4.5% HRI at $100/kW			
2025	20	32	14
2030	47	45	32
2035	44	29	33

Source: Integrated Planning Model, 2018.
Notes: CO_2 emission increases are used to estimate forgone domestic climate benefits. SO_2, and NO_X increases are used for estimating the forgone health benefits from reduced particulate matter and ozone exposures.

Table ES-8 shows projected emission changes relative to the No CPP alternative baseline.

Table ES-8 Projected CO_2, SO_2, and NO_X Electricity Sector Emission Changes, Relative to the No CPP Alternative Baseline (2025-2035)

	CO_2 (million short tons)	SO_2 (thousand short tons)	NO_X (thousand short tons)
Base Case (CPP)			
2025	-50	-36	-32
2030	-74	-60	-47
2035	-66	-44	-43
2% HRI Scenario at $50/kW			
2025	-13	0	-8
2030	-13	-7	-8
2035	-11	-11	-5
4.5% HRI Scenario at $50/kW			
2025	-18	4	-11
2030	-14	-7	-8
2035	-7	-1	-1
4.5% HRI Scenario at $100/kW			
2025	-30	-3	-18
2030	-27	-15	-15
2035	-22	-16	-11

Source: Integrated Planning Model, 2018.

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 contiguous 48 states.

We performed gridded photochemical air quality modeling to support the air quality benefits assessment of this proposal, 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.[3] Table ES-9 reports the combined domestic climate benefits and ancillary health co-benefits attributable to changes in SO_2 and NO_X emissions, discounted at 3 percent and 7 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).[4] Nearly all the $PM_{2.5}$-related forgone benefits reported for each year and for each scenario occur in locations where the annual mean $PM_{2.5}$ concentrations are projected to be below the annual $PM_{2.5}$ standard of 12 µg/m^3. We estimate that only about 1 percent of the $PM_{2.5}$-related premature deaths will occur in locations exceeding the annual PM standard in 2025, 2030 and 2035 (see Chapter 4).

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 NAAQS final rule, in the context of selecting and alternative NAAQS, "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).

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.[5] To give readers insight to the uncertainty in the estimated forgone $PM_{2.5}$

[3] 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.

[4] 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 and reporting the risk of $PM_{2.5}$-attributable premature deaths is consistent with recent RIAs (U.S. EPA 2009b, 2010c, 2010d, 2011a, 2011b, 2011c, 2012, 2013, 2014, 2015a, 2016).

[5] 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

mortality benefits occurring at lower ambient levels, we also report the PM benefits according to alternative concentration cut-points and concentration-response parameters. The percentage of estimated $PM_{2.5}$-related deaths occurring below the lowest measured levels (LML) of the two long-term epidemiological studies we use to estimate risk varies between 16 percent (Krewski et al. 2009) and 79 percent (Lepeule et al. 2012). The percentage of estimated premature deaths occurring above the LML and below the NAAQS ranges between 84 percent (Krewski et al. 2009) and 21 percent (Lepeule et al. 2012). Less than 1% of the estimated premature deaths occur above the annual mean $PM_{2.5}$ NAAQS of 12 µg/m^3.

Below we report the benefits forgone to society for each of the policy scenarios. In these tables, negative values represent forgone benefits and positive benefits represent realized benefits.

In Table ES-9 negative benefits indicate benefits forgone to society. All estimated benefits reported in Table ES-9 are negative, indicating that each of the four illustrative scenarios yield forgone climate benefits and forgone ancillary health co-benefits relative to the base case, which includes the CPP.

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."

Table ES-9 Monetized Benefits, Relative to Base Case (CPP) (billions of 2016$)

	Values Calculated using 3% Discount Rate			Values Calculated using 7% Discount Rate		
	Domestic Climate Benefits	**Ancillary Health Co-Benefits**	**Total Benefits**	**Domestic Climate Benefits**	**Ancillary Health Co-Benefits**	**Total Benefits**
No CPP						
2025	(0.3)	(2.8) to (6.6)	(3.2) to (7.0)	(0.1)	(2.6) to (6.1)	(2.7) to (6.1)
2030	(0.5)	(4.9) to (11.4)	(5.4) to (11.9)	(0.1)	(4.5) to (10.5)	(4.6) to (10.6)
2035	(0.5)	(3.8) to (8.8)	(4.3) to (9.3)	(0.1)	(3.5) to (8.1)	(3.6) to (8.2)
2% HRI at $50/kW						
2025	(0.2)	(2.6) to (5.9)	(2.8) to (6.2)	(0.0)	(2.4) to (5.4)	(2.4) to (5.5)
2030	(0.4)	(4.5) to (10.6)	(4.9) to (11.0)	(0.1)	(4.1) to (9.8)	(4.2) to (9.9)
2035	(0.4)	(3.0) to (7.0)	(3.4) to (7.4)	(0.1)	(2.7) to (6.5)	(2.8) to (6.6)
4.5% HRI at $50/kW						
2025	(0.2)	(2.7) to (6.2)	(2.9) to (6.4)	(0.0)	(2.5) to (5.7)	(2.5) to (5.7)
2030	(0.4)	(4.2) to (9.8)	(4.6) to (10.2)	(0.1)	(3.9) to (9.0)	(3.9) to (9.1)
2035	(0.5)	(4.0) to (9.3)	(4.4) to (9.8)	(0.1)	(3.7) to (8.6)	(3.7) to (8.7)
4.5% HRI at $100/kW						
2025	(0.1)	(2.1) to (4.9)	(2.3) to (5.0)	(0.0)	(2.0) to (4.4)	(2.0) to (4.4)
2030	(0.3)	(3.6) to (8.2)	(3.9) to (8.6)	(0.1)	(3.3) to (7.6)	(3.3) to (7.6)
2035	(0.3)	(2.6) to (6.0)	(2.9) to (6.3)	(0.1)	(2.4) to (5.5)	(2.4) to (5.6)

Notes: Negative benefit values indicate forgone benefits relative to the base case, which includes the CPP. All estimates are rounded to one decimal point, 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 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. Excluded from this comparison are the 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.

Table ES-10 presents the present value (PV) and equivalent annualized value (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 base case, which includes the CPP. The EAV represents an even-flow of figures over the timeframe of 2023-2037 that would yield an equivalent present value. The EAV is identical for each year of the analysis, in contrast to the year-specific estimates presented earlier for the snapshot years of 2025, 2030, and 2035.

In Table ES-10, and all net benefit tables, negative costs indicate avoided costs, negative benefits indicate forgone benefits, and negative net benefits indicate forgone net benefits.

Table ES-10 Present Value and Equivalent Annualized Value of Compliance Costs, Climate Benefits, and Net Benefits Associated with Targeted Pollutant (CO_2), Relative to Base Case (CPP), 3 and 7 Percent Discount Rates, 2023-2037 (billions of 2016$)

	Costs		Domestic Climate Benefits		Net Benefits associated with the Targeted Pollutant (CO_2)	
	3%	**7%**	**3%**	**7%**	**3%**	**7%**
Present Value						
No CPP	(5.2)	(3.1)	(3.9)	(0.4)	1.2	2.7
2% HRI at $50/kW	(0.4)	(0.3)	(3.2)	(0.3)	(2.8)	(0.1)
4.5% HRI at $50/kW	(6.4)	(3.7)	(3.2)	(0.3)	3.2	3.4
4.5% HRI at $100/kW	3.0	1.7	(2.4)	(0.2)	(5.4)	(2.0)
Equivalent Annualized Value						
No CPP	(0.4)	(0.3)	(0.3)	(0.0)	0.1	0.3
2% HRI at $50/kW	(0.0)	(0.0)	(0.3)	(0.0)	(0.2)	(0.0)
4.5% HRI at $50/kW	(0.5)	(0.4)	(0.3)	(0.0)	0.3	0.4
4.5% HRI at $100/kW	0.3	0.2	(0.2)	(0.0)	(0.5)	(0.2)

Notes: Negative costs indicate avoided costs, negative benefits indicate forgone benefits, and negative net benefits indicate forgone net benefits. All estimates are rounded to one decimal point, 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.

Table ES-11 presents the costs, benefits, and net benefits associated with the targeted pollutant for specific years, rather than as a PV or EAV as found in Table ES-10.

Table ES-11 Compliance Costs, Climate Benefits, and Net Benefits Associated with Targeted Pollutant (CO_2), Relative to Base Case (CPP), 3 and 7 Percent Discount Rates, 2025, 2030, and 2035 (billions of 2016$)

	Costs		Domestic Climate Benefits		Net Benefits associated with the Targeted Pollutant (CO_2)	
	3%	**7%**	**3%**	**7%**	**3%**	**7%**
No CPP						
2025	(0.7)	(0.7)	(0.3)	(0.1)	0.4	0.7
2030	(0.7)	(0.7)	(0.5)	(0.1)	0.2	0.6
2035	(0.4)	(0.4)	(0.5)	(0.1)	(0.1)	0.3
2% HRI at $50/kW						
2025	0.0	0.0	(0.2)	(0.0)	(0.3)	(0.1)
2030	(0.2)	(0.2)	(0.4)	(0.1)	(0.2)	0.2
2035	0.1	0.1	(0.4)	(0.1)	(0.6)	(0.2)
4.5% HRI at $50/kW						
2025	(0.6)	(0.6)	(0.2)	(0.0)	0.4	0.6
2030	(1.0)	(1.0)	(0.4)	(0.1)	0.5	0.9
2035	(0.6)	(0.6)	(0.5)	(0.1)	0.2	0.5
4.5% HRI at $100/kW						
2025	0.5	0.5	(0.1)	(0.0)	(0.7)	(0.5)
2030	0.2	0.2	(0.3)	(0.1)	(0.5)	(0.2)
2035	0.5	0.5	(0.3)	(0.1)	(0.8)	(0.5)

Notes: Negative costs indicate avoided costs, negative benefits indicate forgone benefits, and negative net benefits indicate forgone net benefits. All estimates are rounded to one decimal point, 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.

Table ES-12 and Table ES-13 provide the estimated costs, benefits, and net benefits, inclusive of the ancillary health-co benefits. Table ES-12 presents the PV and EAV estimates, and Table ES-13 presents the estimates for the specific years of 2025, 2030, and 2035.

Table ES-12 Present Value and Equivalent Annualized Value of Compliance Costs, Total Benefits, and Net Benefits, Relative to Base Case (CPP), 3 and 7 Percent Discount Rates, 2023-2037 (billions of 2016$)

	Costs		Benefits		Net Benefits	
	3%	**7%**	**3%**	**7%**	**3%**	**7%**
Present Value						
No CPP	(5.2)	(3.1)	(37.2) to (81.5)	(17.9) to (41.3)	(32.0) to (76.3)	(14.8) to (38.2)
2% HRI at $50/kW	(0.4)	(0.3)	(32.7) to (72.4)	(15.9) to (36.9)	(32.3) to (72.0)	(15.7) to (36.7)
4.5% HRI at $50/kW	(6.4)	(3.7)	(34.3) to (75.2)	(16.6) to (39.4)	(27.9) to (68.8)	(12.8) to (35.6)
4.5% HRI at $100/kW	3.0	1.7	(27.2) to (60.2)	(13.9) to (31.9)	(30.2) to (63.2)	(15.6) to (33.7)
Equivalent Annualized Value						
No CPP	(0.4)	(0.3)	(3.1) to (6.8)	(2.0) to (4.5)	(2.7) to (6.4)	(1.6) to (4.2)
2% HRI at $50/kW	(0.0)	(0.0)	(2.7) to (6.1)	(1.7) to (4.1)	(2.7) to (6.0)	(1.7) to (4.0)
4.5% HRI at $50/kW	(0.5)	(0.4)	(2.9) to (6.3)	(1.8) to (4.3)	(2.3) to (5.8)	(1.4) to (3.9)
4.5% HRI at $100/kW	0.3	0.2	(2.3) to (5.0)	(1.5) to (3.5)	(2.5) to (5.3)	(1.7) to (3.7)

Notes: Negative costs indicate avoided costs, negative benefits indicate forgone benefits, and negative net benefits indicate forgone net benefits. All estimates are rounded to one decimal point, 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 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)).

Table ES-13 Compliance Costs, Total Benefits, and Net Benefits, Relative to Base Case (CPP), 3 and 7 Percent Discount Rates, 2025, 2030, and 2035 (billions of 2016$)

	Costs		Benefits		Net Benefits	
	3%	**7%**	**3%**	**7%**	**3%**	**7%**
No CPP						
2025	(0.7)	(0.7)	(3.2) to (7.0)	(2.7) to (6.1)	(2.4) to (6.2)	(1.9) to (5.4)
2030	(0.7)	(0.7)	(5.4) to (11.9)	(4.6) to (10.6)	(4.7) to (11.2)	(3.8) to (9.8)
2035	(0.4)	(0.4)	(4.3) to (9.3)	(3.6) to (8.2)	(3.9) to (8.9)	(3.2) to (7.8)
2% HRI at $50/kW						
2025	0.0	0.0	(2.8) to (6.2)	(2.4) to (5.5)	(2.8) to (6.2)	(2.4) to (5.5)
2030	(0.2)	(0.2)	(4.9) to (11.0)	(4.2) to (9.9)	(4.7) to (10.8)	(3.9) to (9.7)
2035	0.1	0.1	(3.4) to (7.4)	(2.8) to (6.6)	(3.5) to (7.6)	(3.0) to (6.7)
4.5% HRI at $50/kW						
2025	(0.6)	(0.6)	(2.9) to (6.4)	(2.5) to (5.7)	(2.3) to (5.8)	(1.9) to (5.1)
2030	(1.0)	(1.0)	(4.6) to (10.2)	(3.9) to (9.1)	(3.7) to (9.2)	(3.0) to (8.1)
2035	(0.6)	(0.6)	(4.4) to (9.8)	(3.7) to (8.7)	(3.8) to (9.2)	(3.1) to (8.1)
4.5% HRI at $100/kW						
2025	0.5	0.5	(2.3) to (5.0)	(2.0) to (4.4)	(2.8) to (5.5)	(2.5) to (5.0)
2030	0.2	0.2	(3.9) to (8.6)	(3.3) to (7.6)	(4.1) to (8.7)	(3.5) to (7.8)
2035	0.5	0.5	(2.9) to (6.3)	(2.4) to (5.6)	(3.4) to (6.8)	(2.9) to (6.0)

Notes: Negative costs indicate avoided costs, negative benefits indicate forgone benefits, and negative net benefits indicate forgone net benefits. All estimates are rounded to one decimal point, 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 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 Zanobetti & Schwartz. (2008)).

Table ES-14 provides the PV and EAV of costs, benefits, and net benefits relative to the No CPP alternative baseline associated with the targeted pollutant, CO_2.

Table ES-14 Present Value and Equivalent Annualized Value of Compliance Costs, Climate Benefits, and Net Benefits Associated with Targeted Pollutant (CO_2), Relative to the No CPP Alternative Baseline, 3 and 7 Percent Discount Rates, 2023-2037 (billions of 2016$)

	Costs		Domestic Climate Benefits		Net Benefits associated with the Targeted Pollutant (CO_2)	
	3%	**7%**	**3%**	**7%**	**3%**	**7%**
Present Value						
2% HRI at $50/kW	4.8	2.8	0.8	0.1	(4.1)	(2.8)
4.5% HRI at $50/kW	(1.2)	(0.6)	0.7	0.1	2.0	0.7
4.5% HRI at $100/kW	8.2	4.8	1.6	0.2	(6.6)	(4.7)
Equivalent Annualized Value						
2% HRI at $50/kW	0.4	0.3	0.1	0.0	(0.3)	(0.3)
4.5% HRI at $50/kW	(0.1)	(0.1)	0.1	0.0	0.2	0.1
4.5% HRI at $100/kW	0.7	0.5	0.1	0.0	(0.6)	(0.5)

Notes: Negative costs indicate avoided costs, negative benefits indicate forgone benefits, and negative net benefits indicate forgone net benefits. All estimates are rounded to one decimal point, 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.

Table ES-15 provides the estimated costs, benefits, and net benefits, inclusive of the ancillary health-co benefits for the No CPP alternative baseline in PV and EAV forms.

Table ES-15 Present Value and Equivalent Annualized Value of Compliance Costs, Total Benefits, and Net Benefits, Relative to the No CPP Alternative Baseline, 3 and 7 Percent Discount Rates, 2023-2037 (billions of 2016$)

	Costs		Benefits		Net Benefits	
	3%	**7%**	**3%**	**7%**	**3%**	**7%**
Present Value						
2% HRI at $50/kW	4.8	2.8	4.5 to 9.2	2.0 to 4.3	(0.3) to 4.3	(0.9) to 1.5
4.5% HRI at $50/kW	(1.2)	(0.6)	2.9 to 6.3	1.4 to 1.9	4.1 to 7.5	2.0 to 2.6
4.5% HRI at $100/kW	8.2	4.8	10.0 to 21.3	4.1 to 9.4	1.8 to 13.2	(0.8) to 4.5
Equivalent Annualized Value						
2% HRI at $50/kW	0.4	0.3	0.4 to 0.8	0.2 to 0.5	(0.0) to 0.4	(0.1) to 0.2
4.5% HRI at $50/kW	(0.1)	(0.1)	0.2 to 0.5	0.1 to 0.2	0.3 to 0.6	0.2 to 0.3
4.5% HRI at $100/kW	0.7	0.5	0.8 to 1.8	0.4 to 1.0	0.1 to 1.1	(0.1) to 0.5

Notes: Negative costs indicate avoided costs, negative benefits indicate forgone benefits, and negative net benefits indicate forgone net benefits. All estimates are rounded to one decimal point, 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 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.7 Economic and Employment Impacts

The proposed actions have energy market implications. Table ES-16 presents a variety of energy market impacts for 2025, 2030, and 2035 for the four illustrative scenarios, relative to the base case.

Table ES-16 Summary of Certain Energy Market Impacts, Relative to Base Case (CPP) (Percent Change)

	2025	2030	2035
No CPP			
Retail electricity prices	-0.5%	-0.4%	-0.1%
Average price of coal delivered to the power sector	-0.1%	-0.2%	-0.4%
Coal production for power sector use	6.1%	9.2%	9.5%
Price of natural gas delivered to power sector	-1.1%	-0.3%	0.1%
Price of average Henry Hub (spot)	-1.4%	-0.8%	-0.2%
Natural gas use for electricity generation	-1.5%	-1.5%	-0.9%
2% HRI at $50/kW			
Retail electricity prices	-0.3%	-0.2%	-0.1%
Average price of coal delivered to the power sector	0.2%	-0.1%	-0.4%
Coal production for power sector use	5.5%	8.0%	8.4%
Price of natural gas delivered to power sector	-1.1%	-0.9%	-0.4%
Price of average Henry Hub (spot)	-1.4%	-1.3%	-0.6%
Natural gas use for electricity generation	-2.5%	-1.7%	-1.1%
4.5% HRI at $50/kW			
Retail electricity prices	-0.5%	-0.4%	-0.2%
Average price of coal delivered to the power sector	0.7%	0.6%	0.3%
Coal production for power sector use	5.8%	8.6%	9.5%
Price of natural gas delivered to power sector	-1.4%	-1.1%	-0.7%
Price of average Henry Hub (spot)	-1.7%	-1.6%	-1.0%
Natural gas use for electricity generation	-3.4%	-2.5%	-1.9%
4.5% HRI at $100/kW			
Retail electricity prices	-0.2%	0.0%	0.0%
Average price of coal delivered to the power sector	0.5%	0.3%	-0.1%
Coal production for power sector use	4.5%	7.1%	7.4%
Price of natural gas delivered to power sector	-1.3%	-1.1%	-0.7%
Price of average Henry Hub (spot)	-1.6%	-1.6%	-1.0%
Natural gas use for electricity generation	-3.4%	-2.3%	-1.6%

Note: Positive values indicate increases relative to the base case, which includes the CPP.

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 proposed action are discussed more extensively in Chapter 5 of this RIA.

ES.8 Limitations and Uncertainty

The OMB circular Regulatory Analysis (Circular A-4) provides guidance on the preparation of regulatory analyses required under E.O. 12866. Circular A-4 requires a formal quantitative uncertainty analysis for rules with annual economic effects of $1 billion or more.[6] This proposed rulemaking potentially surpasses this $1 billion threshold for both compliance costs and benefits. Throughout this RIA we consider a number of sources of uncertainty, both quantitatively and qualitatively, on benefits and costs. Some of these elements are evaluated using probabilistic techniques. For other elements, where the underlying likelihoods of certain outcomes are unknown, we use scenario analysis to evaluate their potential effect on the benefits and costs of this rulemaking. We summarize key elements of our analysis of uncertainty here:

- The extent to which all coal-fired EGUs will improve heat rates under this proposal, on average;
- The cost to improve heat rates at all affected coal-fired EGUs nationally;
- Uncertainty in monetizing climate-related benefits; and,
- Uncertainty in the estimated health impacts attributable to changes in particulate matter.

We also summarize other potential sources of benefits and costs that may result from this proposed rule that have not been quantified or monetized. We did not account for certain benefits and costs that may affect the size of the estimated net-benefits; these include certain omitted benefits and costs from changes in CO_2, SO_2, and NO_X 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 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.

[6] Office of Management and Budget (OMB), 2003, Circular A-4, https://www.whitehouse.gov/sites/whitehouse.gov/files/omb/circulars/A4/a-4.pdf

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 avoided compliance costs reported in this RIA are not social costs, although elements of the compliance costs are 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 the proposed regulation include those that affect costs and emissions from the electricity sector. As described above, there is uncertainty in the availability of HRI technologies at all affected coal-fired EGUs nationally and their associated costs. In addition, there is uncertainty in future economic conditions that could affect fuel supplies, technology costs, and electricity demand in the electricity sector. Furthermore, changes in the assumed state plan approach for CPP compliance or compliance methods may affect the estimated benefits and costs.

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 rule will affect future levels of $PM_{2.5}$ and ozone both within and beyond current and projected NAAQS non-attainment areas. This RIA does not project changes in attainment status. The U.S. has experienced significant improvement in $PM_{2.5}$ and ozone concentrations. Between 2000 and 2016, $PM_{2.5}$ levels fell by more than 40 percent.[8] Only nine areas in four states were designated nonattainment for the 2012 annual $PM_{2.5}$ NAAQS.[9] The extent to which the health co-benefits and costs 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

[8] https://www.epa.gov/air-trends/air-quality-national-summary#air-quality-trends

[9] https://www.epa.gov/particle-pollution-designations/additional-final-area-designations-and-technical-amendment-2012

ES.9 References

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CHAPTER 1: INTRODUCTION AND BACKGROUND

1.1 Introduction

With this notice, the Environmental Protection Agency (EPA) is proposing three distinct actions, including Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units (EGUs). First, EPA is proposing to replace the Clean Power Plan (CPP) with revised emissions guidelines (the Affordable Clean Energy (ACE) rule) for states to follow in developing implementation plans to reduce greenhouse gas emission from certain EGUs. In the proposed emissions guidelines (UUUUa), consistent with the interpretation described in the proposed repeal of the CPP, the Agency is proposing to determine that heat rate improvement (HRI) measures are the best system of emission reduction (BSER) for existing coal-fired EGUs. Second, EPA is proposing new regulations that provide direction to both EPA and the states on the implementation of emission guidelines. The new proposed implementing regulations would apply to this action and any future emission guideline issued under section 111(d) of the Clean Air Act (CAA). Third, the Agency is proposing revisions to the New Source Review (NSR) program that will help prevent NSR from being a barrier to the implementation of efficiency projects at EGUs.

This report presents the expected costs, benefits and economic impacts of illustrative scenarios representing approaches that states may implement to comply with this proposed rule. This chapter contains background information on this rule, an overview of the regulatory impact analysis conducted and scenarios analyzed, as well as an outline of the chapters in this report.

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 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] EPA has listed more than 60 stationary source categories under this provision.[2] Once EPA lists a source category, EPA must, under CAA section 111(b)(1)(B), establish "standards of performance" for emissions of air pollutants from new sources 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 EPA establishes NSPS for sources in a source category under CAA section 111(b), EPA is also required, under CAA section 111(d)(1), to prescribe regulations for states to submit plans regulating existing sources in that source category for any air pollutant that, in general, is not regulated under the CAA section 109 requirements for the NAAQS or regulated under the CAA section 112 requirements for hazardous air pollutants (HAP). CAA section 111(d)'s 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 EPA for approval, and EPA must approve the state plan if it is "satisfactory."[4] If a state does not submit a plan, or if EPA does not approve a state's plan, then EPA must establish a plan for that state.[5] Once a state receives EPA's approval of its plan, the provisions in the plan become federally enforceable

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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).

against the entity responsible for noncompliance, in the same manner as the provisions of an approved State Implementation Plan (SIP) under the Act.

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 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 and Revisions to New Source Review

This analysis is intended to be an illustrative representation and analysis of the proposed rule to replace the Clean Power Plan.[6] The proposed rule presents a framework for states to develop state plans that will establish standards of performance for existing affected sources of GHG emissions. The proposed rule does not itself specify any standard of performance, but rather establishes the "best system of emission reduction"[7] (BSER), i.e. technology options for heat rate improvements (HRI), that States may choose to rely upon as they develop standards of

[6] For more details on legal authority and justification of this action, see rule preamble.

[7] The best system of emission reduction (BSER) is outlined in the CAA 111(d), see preamble for further discussion.

performance and State plans. The specific technology options that might be used to establish a standard of performance for individual affected sources are unknown. Affected sources may not be able to apply the technology options because they have already adopted these technologies, they are not applicable to the source, or for other reasons. The rule also re-proposes reforms to New Source Review (NSR) that may facilitate the application of HRI technologies from the BSER to sources that the States otherwise may have deemed inapplicable to those sources as part of their state plans.

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 EPA has determined endangers public health and welfare through their contribution to climate change.

1.3.3 Definition of Affected Sources

EPA is proposing that an affected EGU subject to regulation upon finalization of this proposal is any fossil fuel-fired electric utility steam generating unit (*i.e.*, utility boilers) 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 the publication date of this proposal and that meets the following criteria. To be an affected EGU, a fossil fuel-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 fossil fuel (either alone or in combination with any other fuel).

EPA is proposing different applicability criteria than in the CPP to reflect EPA's determination of the BSER for only fossil fuel-fired electric utility steam generating units. In this proposal, EPA does not identify a BSER for stationary combustion turbines and IGCC units and, thus, such units are not affected EGUs for purposes of this action (see discussion below). EPA notes that under the CPP certain EGUs were not considered to be affected EGUs, and therefore were exempt from inclusion in a state plan. Similarly, EPA is proposing that certain EGUs should be excluded from a state's plan based on specific criteria. For specifics on these criteria, see section IV of the preamble.

1.4 Overview of Regulatory Impact Analysis

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

In this RIA, the Agency provides a full benefit cost analysis of four illustrative scenarios. The four illustrative scenarios include a scenario modeling the full repeal of the CPP and three replacement policy scenarios modeling heat rate improvements (HRI) at coal-fired EGUs. Throughout this RIA, these four illustrative policy scenarios are compared against a base case scenario, which represents baseline conditions. The base case scenario includes promulgated regulations, including the CPP. By analyzing against the existing CPP, the reader can understand the combined impact of a repeal and replacement. Inclusion of a no CPP case allows for an understanding of the repeal alone and allows the reader to evaluate the impact of the policy cases against a no CPP scenario. This RIA assumes a mass-based implementation of the CPP for existing affected sources, and does not assume interstate trading. The three illustrative policy scenarios represent potential outcomes of state determinations of standards of performance, and compliance with those standards by affected coal-fired EGUs. This RIA also updates the analysis in the October 2017 RIA for the proposed repeal of the CPP, by updating, among other elements of the analysis, the expected future economic conditions affecting the electricity sector in both the base case, which includes the CPP, and the full repeal scenario. 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.

[8] The analysis in this proposal 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.

Additionally, this RIA includes information about potential impacts of the proposed 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 Base Case

The analysis relies on EPA's Power Sector Modeling Platform v6 using the Integrated Planning Model (IPM). This accounts for changes in the power sector since promulgation of the CPP in 2015, and projects our best understanding of important technological and economic trends into the future. Due to a number of changes in the electricity sector since the CPP was finalized, as documented in the October 2017 RIA for the proposal to repeal the CPP and Chapter 3 of this RIA, the sector has become less carbon intensive over the past several years, and this trend is projected to continue in the future. These changes and trends are reflected in the modeling used for this analysis.

Because air quality modeling was used to determine health co-benefits, the base case included emissions from all sources. Consequently, in addition to rules included in the IPM base case, the base case for this analysis included emissions from, and rules for, non-EGU point sources, on-road vehicles, non-road mobile equipment and marine vessels.[9] 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 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 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 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

[9] 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 on non-EGU emissions on changes in pollution concentrations between the base case and illustrative scenarios is likely small.

of plausible scenarios describing how this proposed regulatory action may affect electricity sector outcomes in the absence of unexpected shocks. The results of this RIA should be viewed in that context.

1.4.2 BSER and Policy Scenarios

Three of the illustrative scenarios model different levels and costs of HRIs applied uniformly at all affected coal-fired EGUs in the contiguous U.S. beginning in 2025. EPA has identified the BSER to be HRI. In the proposed Emission Guidelines, EPA proposes to provide states with a list of candidate HRI technologies that must be evaluated when establishing standards of performance. Each of these illustrative scenarios assumes that the affected sources are no longer subject to the state plan requirements of the CPP (e.g., the mass-based requirements assumed for CPP implementation in the base case for this RIA). 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. 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 many factors into consideration – including among other factors, the remaining useful life of the affected source – when applying the standards of performance.[10] Therefore, any analysis of the proposed rule must be highly illustrative. However, 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. To avoid the impression that EPA can sufficiently distinguish likely standards of performance across individual affected units and their compliance strategies, this analysis assumes different HRI levels and costs are applied uniformly to affected coal-fired EGUs under each of three illustrative policy scenarios:

- **2 Percent HRI at $50/kW**: This illustrative scenario represents a policy case that reflects modest improvements in HRI absent any revisions to NSR requirements. For many years, industry has indicated to the Agency that many sources have not implemented certain

[10] See Section VI of the preamble for a discussion of factors that EPA is proposing to allow states to consider in establishing a standard of performance for state plans in response to this emission guideline.

HRI improvement projects because the burdensome costs of NSR cause such projects to not be viable.[11] Thus, absent NSR reform, HRI at affected units might be expected to be modest. Based on numerous studies and statistical analysis, the Agency believes that the HRI potential for coal-fired EGUs will, on average, range from one to three percent at a cost of $30 to $60 per kilowatt (kW) of EGU generating capacity. The Agency believes that this scenario (2 percent HRI at $50/kW) reasonable represents that range of HRI and cost.

- **4.5 Percent HRI at $50/kW**: This illustrative scenario represents a policy case that includes benefits from the proposed revisions to NSR, with the HRI modeled at a low cost. As mentioned earlier, the Agency is proposing revisions to the NSR program that will provide owners and operators of existing EGUs greater ability to make efficiency improvements without triggering provisions of NSR. This scenario is informative in that it represents the ability of all coal-fired EGUs to obtain greater improvements in heat rate because of NSR reform at the $50/kW cost identified earlier. EPA believes this higher heat rate improvement potential is possible because without NSR a greater number of units may have the opportunity to make cost effective heat rate improvements such as turbine upgrades that have the potential to offer greater heat rate improvement opportunities.
- **4.5 Percent HRI at $100/kW**: This illustrative scenario represents a policy case that includes the benefits from the proposed revisions to NSR, with the HRI modeled at a higher cost. This scenario is informative in that it represents the ability of a typical coal-fired EGUs to obtain greater improvements in heat rate because of NSR reform but at a much higher cost ($100/kW) than the $50/kW cost identified earlier. Particularly for lower capacity units or those with limited remaining useful life, this could ultimately translate into HRI projects with higher costs.

Combined, the 4.5 percent HRI at $50/kW scenario and the 4.5 percent HRI at $100/kW scenario represent a range of potential costs for the proposed policy option that couples HRI with NSR reform. Modeling this at $50/kW and $100/kW provides a sensitivity analysis on the cost of the proposed policy including NSR reform. The $50/kW cost represents an optimistic bounding where NSR reform unleashes significant new opportunity for low-cost heat rate improvements. The $100/kW cost scenario, while informative, represents a higher cost scenario, particularly for

[11] As expressed by one industry representative, “EGUs engaging in HRI projects can face NSR pre-construction permitting requirements consisting of, at a minimum, costly, detailed analyses and permitting delays. In some cases, this has resulted in costly and protracted litigation, and expensive new emission control requirements, both of which result in substantial time delays for these projects. These concerns remain should unit operators pursue HRI upgrades—many of which EPA has mentioned in the ANPR—that could trigger NSR in an effort to comply with emissions standards designed to comply with revised CAA section 111(d) GHG emissions guidelines.” *See* Edison Electric Institute comments on the U.S. Environmental Protection Agency's Advanced Notice of Proposed Rulemaking entitled, "State Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units," 82 FR 61507 (Dec. 28, 2017) at 22 (EPA-HQ-OAR-2017-0545-0221).

lower capacity factor units and those with limited remaining useful life. Additional information describing the analytical basis for these illustrative scenarios is provide in Section 1.6.

1.4.3 Years of Analysis

We evaluate the potential regulatory impacts of the illustrative No CPP scenario and the three illustrative policy scenarios 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 beginning-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 2025-2037. The year 2025 is an approximation for when the standards of performance under the proposed 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 EPA is proposing to constitute the BSER are summarized below, and are described in greater detail in Section V 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 (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. A major difficulty associated with the use of regenerative air pre-heaters is air leakage from the combustion air side to the flue gas side. Air leakage affects boiler efficiency due to lost heat recovery and affects the axillary load since any 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 leakage.

1.5.4 Variable Frequency Drives (VFDs)

1.5.4.1 VFD on ID Fans

The increased pressure required to maintain proper flue gas flow through add-on air pollutant control equipment may require additional fan power, which can be achieved by an induced draft (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 baseload 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, but 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 V of the preamble provides a list of some reports, case studies, and analyses about heat rate improvement opportunities in the U.S.

1.6 Development of Illustrative Policy Scenarios

1.6.1 Technical Basis

The illustrative scenarios modeled are 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, EPA considered how the available HRI measures that are included in the BSER list of candidate technologies (see Table 1-1) may apply to these categories. This initial analysis uses the HRI percentages from the findings of the EPA-sponsored 2009 Sargent & Lundy (S&L) study[13] and applies S&L study costs that were updated to 2016 dollars. EPA evaluated a case that assumed current NSR requirements that industry claims to be a major deterrent to coal-fired EGU efficiency improvements and a case that reflects implementation of the proposed NSR reforms that will provide the regulatory clarity needed for industry to make HRI improvements without triggering NSR (i.e., the NSR reform scenarios). These cases are referred to respectively as the "no NSR reform" and "NSR reform" cases.

The analysis uses the population of existing coal-fired steam EGUs that are included in the NEEDS v6 database that have a capacity greater than or equal to 25 MW and for which the database does not reflect a planned retirement date prior to 2024.[14] These coal-fired steam EGUs were binned by capacity in the following three size categories (1) those ≤ 200 MW, (2) those that are > 200 MW to those that are ≤ 500 MW, and (3) those that are > 500 MW. This breakdown by size allows use of the breakdown of HRI and cost by size (200 MW, 500 MW, and 900 MW) in the S&L study and allowed the analyses to capture differences based on unit size.

[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 costs and HRI potentials used here are not those used in the EIA study. Furthermore, as described below, given uncertainty in the applicability of HRI to individual units, the analysis in this RIA applies a given HRI levels and costs uniformly to affected coal-fired EGUs in each of the three illustrative policy scenarios.

[13] "Coal-Fired Power Plant Heat Rate Reductions" Sargent & Lundy report SL-009597 (2009) https://www.epa.gov/sites/production/files/2015-08/documents/coalfired.pdf

[14] NEEDS v6 is the database of generating units and their characteristics that is used in the modeling described in Chapter 3. The database includes information on the primary fuel type, nameplate capacity, on-line year, and heat rate for each generating unit used in the analysis described in this section. For additional information, see: https://www.epa.gov/airmarkets/national-electric-energy-data-system-needs-v6

Within each capacity bin, the units were divided into heat rate quartiles based on reported heat rates used in NEEDS, with the first quartile (Q1) representing the most efficient 25 percent of units in the bin and the fourth quartile (Q4) representing the least efficient 25 percent of units in the bin. 3. EPA assumed that better performing units (i.e., those in Q1 and Q2) will have fewer opportunities for heat rate improvements than the lesser performing units. The units in each case were then separated by their on-line year because the EIA study determined that units that came online after 1990 generally offered the smallest HRI potentials. In the EIA study fewer HRI were applied to units that came on line after 1990 relative to the remainder of the fleet because on average the units that came on-line after 1990 had lower heat rates.[15] The availability of HRI candidate technologies that were assumed to be available to units in different quartiles and on-line years are based on the assumptions identified in Table 1-1 for the "No NSR Reform" case and in Table 1-2 for the "NSR Reform" case. The actual applicability of these technologies to each of the capacity bins and quartile ranges is unknown given limited information on the availability of further HRI opportunities coal-fired EGUs. For the purposes of this initial step in identifying illustrative scenarios for this RIA, the assumed applicability of these HRI technologies to the different bins is based on EPA's expert judgement, which is based in part on a review of existing technical studies identified in the preamble.

For the "No NSR Reform" case, the analysis assumed that the "steam turbine upgrade" and the "redesign/replace the economizer" HRI options would not be available as those are among the efficiency improvements that industry believes will trigger NSR. EPA solicits comment on that assumption. In this analysis, those HRI are assumed to not be available for any units. For the "NSR Reform" case, the analysis assumed that the "steam turbine upgrade" and the "redesign/replace the economizer" HRI options would be available for some units.

[15] The EIA study used a different inventory of existing coal-fired EGUs to divide EGUs into heat rate quartiles than the inventory that EPA uses in this analysis. In the EIA study, 70% of the units that came online after 1990 fell into EIA's first and second quartile bins, so fewer HRI measures were attached to them.

Table 1-1 Availability of Heat Rate Improvement Candidate Technologies ("No NSR Reform" Case)

	On-Line Year	
Heat Rate Improvement Technology	**<1990**	**>=1990**
Neural Network/Intelligent Sootblowers	Q2, Q3, Q4	Q2, Q3, Q4
Boiler Feed Pumps	Q2, Q3, Q4	Q4
Air Heater & Duct Leakage Control	Q2, Q3, Q4	Q4
Variable Frequency Drives	Q2, Q3, Q4	Q3, Q4
Blade path upgrade (steam turbine)	-	-
Redesign and replace economizer	-	-

Table 1-2 Availability of Heat Rate Improvement Candidate Technologies ("NSR Reform" Case)

	On-Line Year	
Heat Rate Improvement Technology	**<1990**	**≥1990**
Neural Network/Intelligent Sootblowers	Q2, Q3, Q4	Q2, Q3, Q4
Boiler Feed Pumps	Q2, Q3, Q4	Q4
Air Heater & Duct Leakage Control	Q2, Q3, Q4	Q4
Variable Frequency Drives	Q2, Q3, Q4	Q3, Q4
Blade path upgrade (steam turbine)	Q2, Q3, Q4	Q3, Q4
Redesign and replace economizer	Q2, Q3, Q4	Q3, Q4

All of the performance of the available HRI measures in this analysis are based on the range of HRI potentials and costs reported in S&L study with costs adjusted to $2016.[16] The performance and costs are in Table 1-3 and Table 1-4. Note that these costs reflect the range reported by S&L using their methodology and do not reflect the full range in the cost of these technologies for all potential applications at coal-fired EGUs. All operating costs for HRI measures, which are capital-intensive, were converted to a capital cost equivalent assuming a typical size and capacity factor in each capacity bin.

[16] EIA (2015) used different HRI costs and potentials than those used here.

Table 1-3 Heat Rate Improvement Potential (%)

Heat Rate Improvement Candidate Technologies	<200 MW		200 to 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
Blade path upgrade (steam turbine)	0.9	2.7	1.0	2.9	1.0	2.9
Redesign and replace economizer	0.5	0.9	0.5	1.0	0.5	1.0

Table 1-4 Heat Rate Improvement Cost ($2016/kW)

Heat Rate Improvement Candidate Technologies	<200 MW		200 to 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	$2.5	$2.7	$2.1	$2.4
Variable Frequency Drives	$9.1	$11.9	$7.2	$9.4	$6.6	$7.9
Blade path upgrade (steam turbine)	$11.2	$66.9	$8.9	$44.6	$6.2	$31.0
Redesign and replace economizer	$13.1	$18.7	$10.5	$12.7	$10.0	$11.2

After applying each relevant available technology to the universe of coal steam units for each of the policy cases (i.e., “No NSR Reform” and “NSR Reform”), the fleet-wide capacity weighted average HRI (%) and cost ($/kW) were calculated for both the minimum and maximum of the ranges presented in the S&L study and are shown in Tables 1-5 and 1-6. We assume that the minimum range of performance corresponds to the minimum range of cost, while the maximum performance corresponds with the maximum cost.

Table 1-5 Fleet-Wide Capacity Weighted Average Improvement and Costs ("No NSR Reform" Case)

	Min	Max
Heat Rate Improvement (%)	0.6%	2.0%
Costs ($/kW)	$8	$10

Table 1-6 Fleet-Wide Capacity Weighted Average Improvement and Costs ("NSR Reform" Case)

	Min	Max
Heat Rate Improvement (%)	1.6%	4.7%
Costs ($/kW)	$21	$44

Again, to avoid the impression that EPA can sufficiently distinguish likely standards of performance across individual affected units and their compliance strategies, this analysis assumes different HRI levels and costs are applied uniformly to affected coal-fired EGUs under each of three illustrative policy scenarios. The illustrative scenario that assumes no revisions to NSR applies an HRI of 2.0 percent, which is consistent with the high end of HRI percentage determined from the "No NSR Reform" case. We choose the high end of the HRI percentage reduction on heat rates to evaluate the possible influence of a system-wide rebound effect, which is the increase in system-wide generation that may accompany an improvement in fuel efficiency, on the benefits and costs of the proposed rule. For the cost of HRI in this illustrative scenario, EPA uses higher costs relative to the average cost shown in Table 1-5 ($8 to $10/kW). EPA selected a cost per kW of HRI from the low-end of the range of HRI costs identified in the BSER Building Block 1 analysis for the Final CPP (USEPA 2015).

For the two illustrative scenarios that assume revisions to NSR apply an HRI of 4.5 percent which is consistent with the high end of HRI (%) determined from the "NSR Reform" case. Again, we choose the high end of the HRI percentage reduction to evaluate the potential rebound effect. For the scenario that assumes a fleet-wide HRI of 4.5 percent at cost of $50/kW we round up the cost from the high end of the cost to $50/kW. This cost is also consistent with the range of costs identified in the BSER Building Block 1 analysis for the Final CPP (Ibid.). For the scenario that assumes a fleet-wide 4.5 percent HRI at a cost of $100/kW we apply a higher cost because 1) those EGUs for which these technologies are costlier may be installing them when the technologies are widely adopted, 2) other studies identify blade path upgrades and economizer redesign and replacements as more expensive HRI technologies than the S&L study, and 3) $100/kW is at the upper-end of the range of the BSER Building Block 1 analysis for the Final CPP (Ibid.).

The quantitative results of the scenarios with and without NSR revisions, because of the analytical approach informing the different illustrative scenarios, cannot be directly compared to each other. The analytical basis supporting the performance and cost of HRI differs across the scenarios for reasons other than the whether there are or are not revisions to NSR are represented, and therefore the incremental differences between the illustrative scenarios cannot be fully attributed to differences in NSR. However, the directional differences between the illustrative scenarios across time are nonetheless generally informative.

As described in the preamble for this proposal, EPA is taking comment on the costs, performance, and availability of the HRI technologies that constitute BSER for fossil steam EGUs. Based on any new information EPA receives, and considering existing studies evaluating HRI cost and potential, EPA will consider changes to its analysis to reflect a different representation of the potential heterogeneity in HRI potential across different types of fossil-steam EGUs and the average HRI improvement expected across the fleet. These might include, but are not limited to, the heat rate, age, remaining useful life, utilization, and size of EGUs. While it may be possible to generalize differences in HRI availability across different types of units, the circumstances of individual units will still be unknown, and for this reason such generalizations may not necessarily apply to specific EGUs.

1.6.2 How HRI are Represented in the Policy Scenarios

As discussed above, the proposed regulation requires states to develop standards of performance based on the BSER, which EPA has determined to be HRI at existing EGUs. Conceptually, the illustrative policy scenarios presume 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). For example, the illustrative scenarios with a greater percentage HRI presume a numerically more stringent standard of performance than the scenario with a lower percentage HRI. 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 of performance the states will require are uncertain.[17] 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 scenarios, 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 proposed rule when applying BSER to avoid implementing HRI and retirement of affected sources, and the scenarios do not capture this possibility.

The three illustrative policy scenarios reflect a range of technology improvements applied uniformly across the fleet. 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 EPA used the best available information, research, and analysis to arrive at the assumptions used in these three scenarios.

1.7 Organization of the Regulatory Impact Analysis

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

- Chapter 2, Electric Power Sector Industry Profile
- 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

[17] 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.

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National Research Council. *Climate Stabilization Targets: Emissions, Concentrations, and Impacts over Decades to Millennia*. Washington, DC: The National Academies Press, 2011.

USEPA, 2015. *Greenhouse Gas Mitigation Measures.* Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Utility Generating Units. Docket ID No. EPA-HQ-OAR-2013-0602

CHAPTER 2: ELECTRIC POWER SECTOR INDUSTRY PROFILE

2.1 Introduction

This chapter discusses important aspects of the power sector that relate to this proposed rulemaking, including the types of power-sector sources affected by the regulation, and provides background on the power sector and EGUs. In addition, this chapter provides some historical background on trends in the past decade in the power sector, as well as about existing EPA regulation of the power sector.

In the past decade there have been significant structural changes in both the mix of generating capacity and in the share of electricity generation supplied by different types of generation. These changes are the result of multiple factors in the power sector, including normal replacements of older generating units with new units, changes in the electricity intensity of the US economy, growth and regional changes in the US population, technological improvements in electricity generation from both existing and new units, changes in the prices and availability of different fuels, and substantial growth in electricity generation by renewable and unconventional methods. Many of these trends will continue to contribute to the evolution of the power sector. The evolving economics of the power sector, in particular the increased natural gas supply and subsequent relatively low natural gas prices, have resulted in more gas being utilized as baseload energy in addition to supplying electricity during peak load. This chapter presents data on the evolution of the power sector from 2006 through 2016. Projections of new capacity and the impact of this rule on these new sources are discussed in more detail in Chapter 3 of this RIA.

2.2 Power Sector Overview

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

2.2.1 Generation

Electricity generation is the first process in the delivery of electricity to consumers. There are two important aspects of electricity generation; capacity and net generation. Generating Capacity refers to the maximum amount of production from an EGU in a typical hour, typically measured in megawatts (MW) or gigawatts (1 GW = 1000 MW). Electricity Generation refers to the amount of electricity actually produced by EGUs, measured in kilowatt-hours (kWh) or gigawatt-hours (GWh = 1 million kWh). Net Generation is the amount of electricity that is available to the grid from the EGU (i.e., excluding the amount of electricity generated but used within the generating station for operations). In addition to producing electricity for sale to the grid, generators perform other services important to reliable electricity supply, such as providing backup generating capacity in the event of unexpected changes in demand or unexpected changes in the availability of other generators. Other important services provided by generators include facilitating the regulation of the voltage of supplied generation.

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

Most of the existing capacity generates electricity by creating heat to create high pressure steam that is released to rotate turbines which, in turn, create electricity. Natural gas combined cycle (NGCC) units have two generating components operating from a single source of heat. The first cycle is a gas-fired turbine, which generates electricity directly from the heat of burning natural gas. The second cycle reuses the waste heat from the first cycle to generate steam, which is then used to generate electricity from a steam turbine. Other EGUs generate electricity by using water or wind to rotate turbines, and a variety of other methods including direct photovoltaic generation also make up a small, but growing, share of the overall electricity supply. The generating capacity includes fossil-fuel-fired units, nuclear units, and hydroelectric and other renewable sources (see Table 2-1). Table 2-1 also shows the comparison between the generating capacity in 2006 and 2016.

In 2016, the power sector consisted of over 19,000 generating units with a total capacity[1] of 1,177 GW, an increase of 102 GW (or 9 percent) from the capacity in 2006 (1,076 GW). The 101 GW increase consisted primarily of natural gas fired EGUs (70 GW) and wind generators (71 GW), other renewables (26 GW), and miscellaneous (4 GW) with substantially smaller net increases and decreases in other types of generating units.

Table 2-1 Existing Electricity Net Summer Generating Capacity by Energy Source, 2006 and 2016

	2006		2016		Change Between '06 and '16		
Energy Source	**Generator Net Summer Capacity (MW)**	**% Total Capacity**	**Generator Net Summer Capacity (MW)**	**% Total Capacity**	**% Change**	**Net Summer Capacity Change (MW)**	**% of Total Capacity Change**
Coal	312,956	32%	266,620	25%	-15%	-46,336	-53%
Natural Gas[1]	388,294	39%	446,823	42%	15%	58,529	66%
Nuclear	100,334	10%	99,565	9%	-1%	-769	-1%
Hydro	99,282	10%	102,692	10%	3%	3,410	4%
Petroleum	58,097	6%	34,382	3%	-41%	-23,715	-27%
Wind	11,329	1%	81,287	8%	618%	69,958	79%
Solar	--	--	21,951	2%	--	--	--
Other Renewable	12,784	1%	16,542	2%	29%	3,757	4%
Misc.	3,139	0%	4,472	0%	42%	1,333	2%
Total	986,215	100%	1,074,333	100%	9%	88,118	100%

Source: U.S. EIA Electric Power Annual, Tables 4.2.A, 4.2.B
Note: This table presents generation capacity. Actual net generation is presented in Table 2 2. 2006 solar data is not reported in the U.S. EIA Electric Power Annual.
[1] Natural Gas information in this chapter (unless otherwise stated) reflects data for all generating units using natural gas as the primary fossil heat source. This includes Natural Gas Fired Combined Cycle (59 percent of 2016 natural gas fired capacity), Natural Gas Fired Combustion Turbine (35 percent of 2016 natural gas fired capacity), Natural Gas Internal Combustion (5 percent of 2016 natural gas fired capacity), and Other Natural Gas (< 1 percent).

[1] As with all data presented in this section, this includes generating capacity not only at EGUs primarily operated to supply electricity to the grid, but also generating capacity at commercial and industrial facilities that produce both electricity used onsite as well as dispatched to the grid. Unless otherwise indicated, capacity data presented in this RIA is installed nameplate capacity (also known as nominal capacity), defined by EIA as “The maximum rated output of a generator, prime mover, or other electric power production equipment under specific conditions designated by the manufacturer.” Nameplate capacity is consistently reported to regulatory authorities with a common definition, where alternate measures of capacity (e.g., net summer capacity and net winter capacity) can use a variety of definitions and specified conditions.

The nine percent increase in generating capacity is the net impact of newly built generating units, retirements of generating units, and a variety of increases and decreases to the nameplate capacity of individual existing units due to changes in operating equipment, changes in emission controls, etc. During the period 2006 to 2016, a total of 228 GW of new generating capacity was built and brought online, while 111 GW of electric generating capacity was retired. The changes in capacity are shown in Figure 2-1.

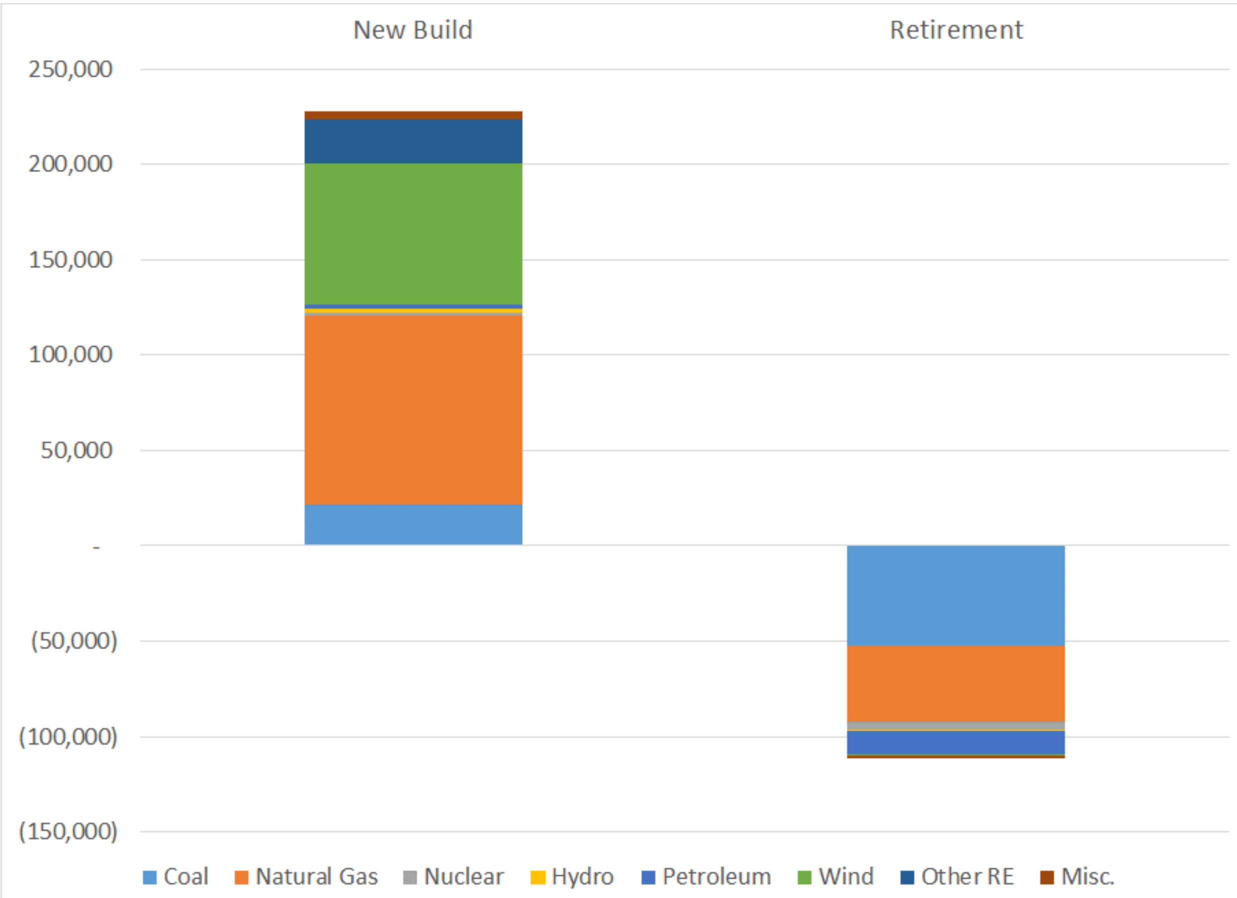

Figure 2-1 New Build and Retired Capacity (MW) by Technology, 2006-2016
Source: EIA Form 860 (2016)

In 2016, electric generating sources produced a net 4,077 trillion kWh to meet electricity demand, a 0.3 percent increase from 2006 (11 trillion kWh). As presented in Table 2-2, 65 percent of electricity in 2016 was produced through the combustion of fossil fuels, primarily coal and natural gas, with natural gas accounting for the largest single share. Although the share of the total generation from fossil fuels in 2016 (65 percent) was only modestly smaller than the total fossil share in 2006 (71 percent), the mix of fossil fuel generation changed substantially during that period. Coal generation declined by 38 percent and petroleum generation by 62 percent, while natural gas generation increased by 69 percent. This reflects both the increase in natural gas capacity during that period as well as an increase in the utilization of new and existing gas EGUs during that period. Wind generation also grew from a very small portion of the overall total in 2006 to 6 percent of the 2016 total.

Table 2-2 Net Generation in 2006 and 2016 (Trillion kWh = TWh)

	2006		2016		Change Between '06 and '16	
Energy Source	**Net Generation (TWh)**	**Fuel Source Share**	**Net Generation (TWh)**	**Fuel Source Share**	**Net Generation Change (TWh)**	**% Change in Net Generation**
Coal	1,991	49%	1,239	30%	-751	-38%
Natural Gas	816	20%	1,378	34%	562	69%
Nuclear	787	19%	806	20%	18	2%
Hydro	283	7%	261	6%	-22	-8%
Petroleum	64	2%	24	1%	-40	-62%
Wind	27	1%	227	6%	200	754%
Solar	1	0%	36	1%	36	6997%
Other Renewable	69	2%	79	2%	9	13%
Misc.	27	1%	27	1%	-1	-2%
Total	4,065	100%	4,077	100%	12	0.3%

Source: U.S. EIA Electric Power Annual, Tables 3.1.A, 3.1.B

Coal-fired and nuclear generating units have historically supplied baseload electricity, the portion of electricity loads which are continually present, and typically operate throughout all hours of the year. There can be notable differences across various facilities (see Table 2-3). For example, coal-fired units less than 100 megawatts (MW) in size compose 37 percent of the total number of coal-fired units, but only 6 percent of total coal-fired capacity. Gas-fired generation is better able to vary output and is the primary option used to meet the variable portion of the electricity load and has historically supplied “peak” and “intermediate” power, when there is increased demand for electricity (for example, when businesses operate throughout the day or when people return home from work and run appliances and heating/air-conditioning), versus late at night or very early in the morning, when demand for electricity is reduced.

Table 2-3 also shows comparable data for the capacity and age distribution of natural gas units. Compared with the fleet of coal EGUs, the natural gas fleet of EGUs is generally smaller and newer. Many of the largest gas units are gas-fired steam-generating EGUs.

Table 2-3 Coal and Natural Gas Generating Units, by Size, Age, Capacity, and Thermal Efficiency (Heat Rate)

Unit Size Grouping (MW)	No. Units	% of All Units	Avg. Age	Avg. Net Summer Capacity (MW)	Total Net Summer Capacity (MW)	% Total Capacity	Avg. Heat Rate (Btu/kWh)
COAL							
0 – 24	33	6%	57	11	375	0%	12,362
25 – 49	41	7%	41	37	1,499	1%	12,050
50 – 99	39	7%	47	74	2,894	1%	11,929
100 – 149	45	8%	57	122	5,485	2%	11,266
150 – 249	88	15%	54	193	17,013	8%	10,899
250 – 499	140	23%	46	368	51,468	23%	10,605
500 – 749	143	24%	45	609	87,055	39%	10,301
750 – 999	56	9%	42	827	46,293	20%	10,069
1000 - 1500	11	2%	47	1257	13,831	6%	9,802
Total Coal	596	100%	48	379	225,913	100%	10,843
NATURAL GAS							
0 – 24	3950	53%	38	5	20,425	5%	14,144
25 – 49	910	12%	31	41	37,065	9%	11,968
50 – 99	983	13%	30	71	69,749	17%	12,274
100 – 149	371	5%	25	127	47,248	11%	9,116
150 – 249	991	13%	20	178	176,610	43%	8,034
250 – 499	178	2%	16	319	56,727	14%	7,017
500 – 749	7	0.1%	11	549	3,840	1%	6,881
Total Gas	7,390	100%	33	56	411,663	100%	12,377

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

Note: Natural gas includes combustion turbines and combined cycles. The average heat rate reported is the mean of the heat rate of each unit. A lower heat rate indicates a higher level of fuel efficiency. Table is limited to coal-steam units in operation in 2016, and excludes units with planned retirements prior to 2025. Age is estimated for the year 2025.

In terms of the age of the generating units, by 2025, over 50 percent of the total existing coal generating capacity will have been in service for more than 47 years, while about 50 percent of the existing natural gas capacity will have been in service for 22 years. Figure 2-2 presents the cumulative age distributions of the coal and gas fleets, highlighting the pronounced differences in the ages of the fleets of these two types of fossil-fuel generating capacity.

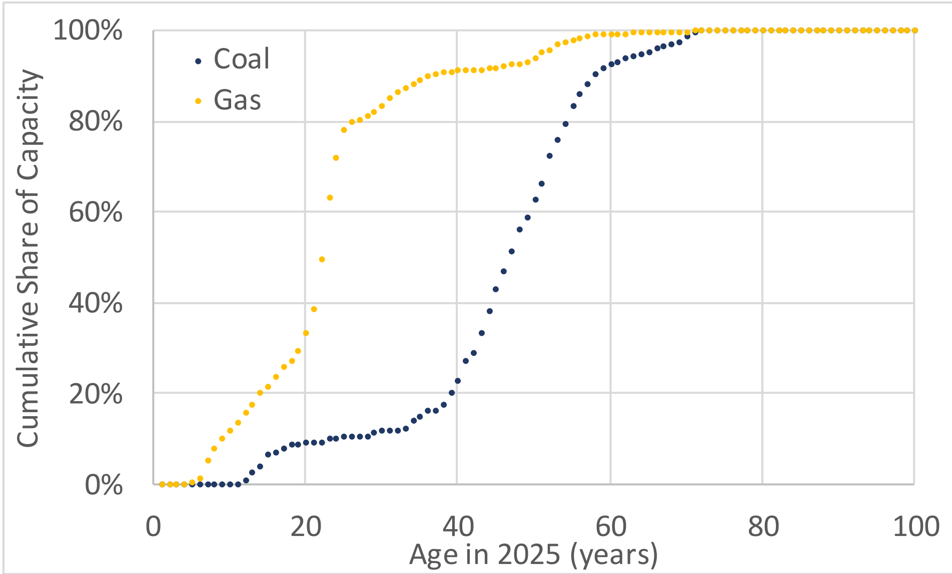

Figure 2-2 Cumulative Distribution in 2025 of Coal and Natural Gas Electricity Capacity by Age

Source: National Electric Energy Data System (NEEDS) v6

Note: Natural gas includes combustion turbines and combined cycles. Table is limited to coal-steam units in operation in 2016 or earlier, and excludes those units in NEEDS with planned retirements prior to 2025. Age is estimated in the year 2025.

Capacity factors measure the amount of electricity produced relative to the maximum potential production for a given generator. The 2016 average capacity factors for coal steam generators in the contiguous U.S. are depicted in Figure 2-3 and Figure 2-4. These figures demonstrate that, in 2016, domestic coal generators operated over a wide range of capacity factors. While many of these generators were designed to operate at annual average capacity factors of 80 to 85 percent, most of these generators were operating at considerably lower capacity factors in 2016, regardless of age or capacity.

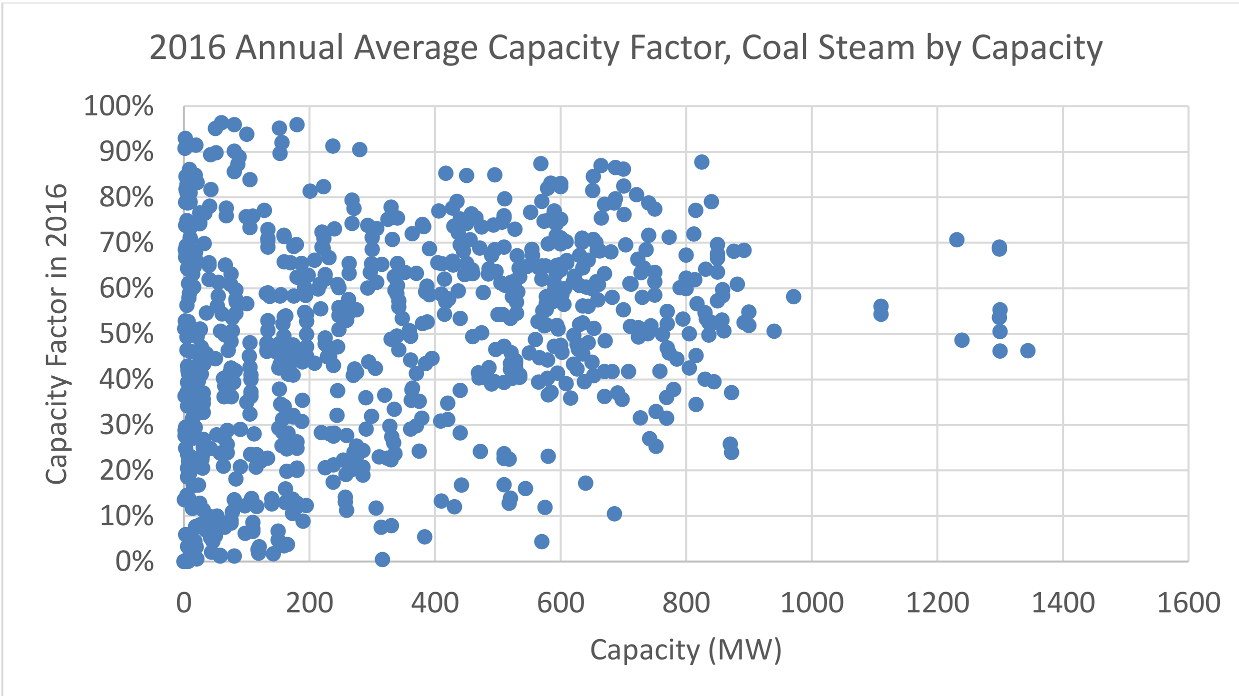

Figure 2-3 2016 Annual Average Capacity Factor for Coal Steam Generators, by Capacity

Source: EIA Forms 860 and 923

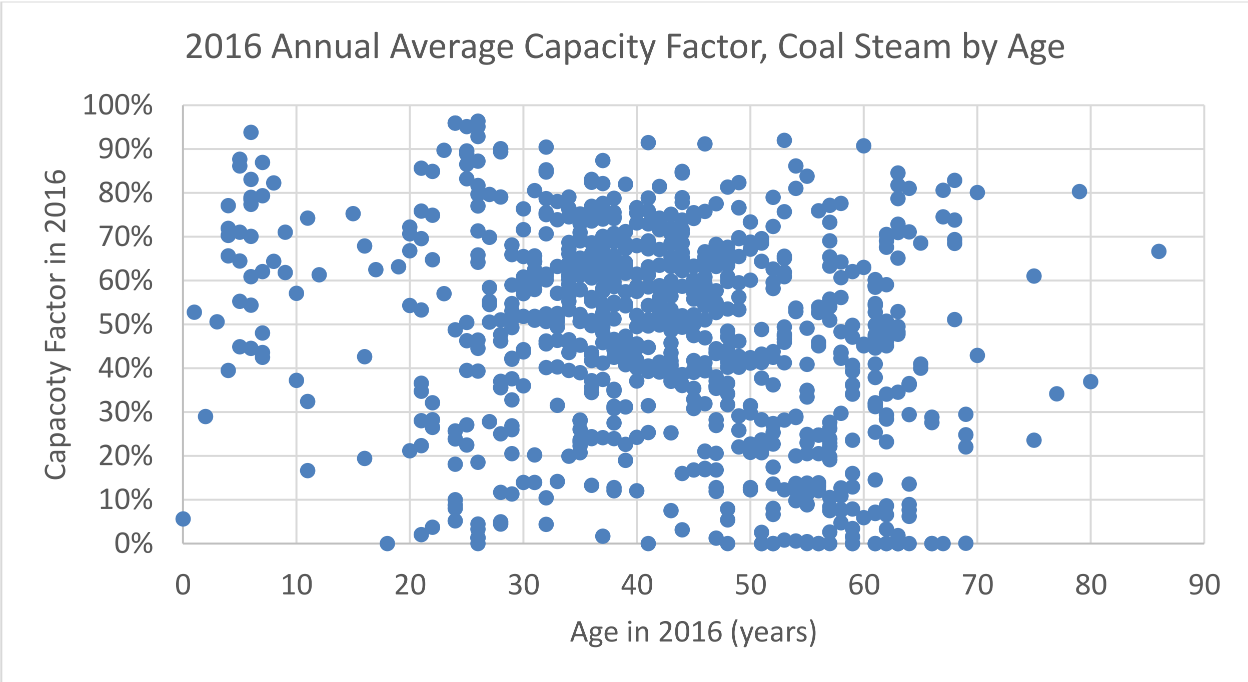

Figure 2-4 2016 Annual Average Capacity Factor for Coal Steam Generators, by Age in 2016

Source: EIA Forms 860 and 923

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

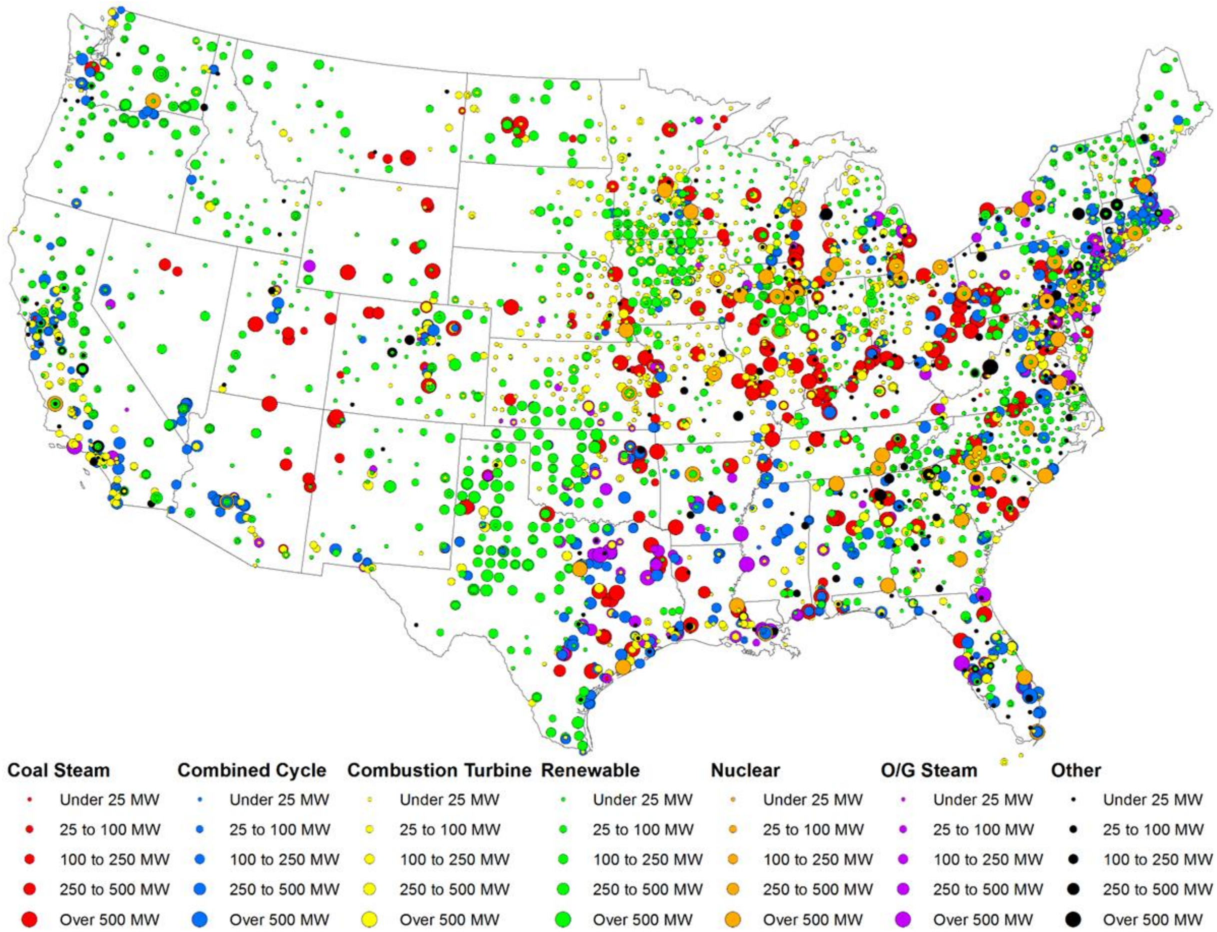

Figure 2-5 Electricity Generating Facilities, by Size and Type
Source: National Electric Energy Data System (NEEDS) v.6

Note: This map displays generating capacity at facilities in the NEEDS v.6 database. This database reflects available capacity online by the end of 2021 and includes planned new builds already under construction and planned retirements. In areas with a dense concentration of facilities, some facilities may be obscured.

2.2.2 Transmission

Transmission is the term used to describe the bulk transfer of electricity over a network of high voltage lines, from electric generators to substations where power is stepped down for local distribution. In the U.S. and Canada, there are three separate interconnected networks of high voltage transmission lines,[2] each operating synchronously. Within each of these

[2] These three network interconnections are the Western Interconnection, comprising the western parts of both the US and Canada (approximately the area to the west of the Rocky Mountains), the Eastern Interconnection, comprising

transmission networks, there are multiple areas where the operation of power plants is monitored and controlled by regional organizations to ensure that electricity generation and load are kept in balance. In some areas, the operation of the transmission system is under the control of a single regional operator[3]; in others, individual utilities[4] coordinate the operations of their generation, transmission, and distribution systems to balance the system across their respective service territories.

2.2.3 Distribution

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

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

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the eastern parts of both the US and Canada (except those part of eastern Canada that are in the Quebec Interconnection), and the Texas Interconnection (which encompasses the portion of the Texas electricity system commonly known as the Electric Reliability Council of Texas (ERCOT)). See map of all NERC interconnections at http://www.nerc.com/AboutNERC/keyplayers/Documents/NERC_Interconnections_Color_072512.jpg

[3] E.g., PMJ Interconnection, LLC, Western Area Power Administration (which comprises 4 sub-regions).

[4] E.g., Los Angeles Department of Power and Water, Florida Power and Light.

and distribution assets to form distinct economic entities. Transmission and distribution remain price-regulated throughout the country based on the cost of service.

2.3 Sales, Expenses and Prices

These electric generating sources provide electricity for commercial, industrial and residential ultimate customers. Each of the three major ultimate categories consume roughly a quarter to a third of the total electricity produced[5] (see Table 2-4). Some of these uses are highly variable, such as heating and air conditioning in residential and commercial buildings, while others are relatively constant, such as industrial processes that operate 24 hours a day. The distribution between the end use categories changed very little between 2006 and 2016.

Table 2-4 Total U.S. Electric Power Industry Retail Sales in 2006 and 2016 (billion kWh)

		2006		2016	
		Sales/Direct Use (Billion kWh)	**Share of Total End Use**	**Sales/Direct Use (Billion kWh)**	**Share of Total End Use**
Sales	Residential	1,352	35%	1,411	36.2%
	Commercial	1,300	34%	1,367	35.0%
	Industrial	1,011	26%	977	25.0%
	Transportation	7		7	0.2%
	Other	N/A	0.2%	NA	
Total		3,670	96%	3,762	96%
Direct Use		147	4%	140	4%
Total End Use		**3,817**	100%	**3,902**	100%

Source: Table 3.2, EIA Electric Power Annual, 2016

Notes: Retail sales are not equal to net generation (Table 2-2) because net generation includes net exported electricity and loss of electricity that occurs through transmission and distribution.

Direct Use represents commercial and industrial facility use of onsite net electricity generation; and electricity sales or transfers to adjacent or co-located facilities for which revenue information is not available.

2.3.1 Electricity Prices

Electricity prices vary substantially across the United States, differing both between the ultimate customer categories and also by state and region of the country. Electricity prices are typically highest for residential and commercial customers because of the relatively high costs of

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

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

On a state-by-state basis, all retail electricity prices vary considerably. In 2016, the national average retail electricity price (all sectors) was 10.41 cents/kWh, with a range from 7.46 cents (Louisiana) to 23.87 (Hawaii). The Northeast, California and Alaska have average retail prices that can be as much as double those of other states (see Figure 2-6), and Hawaii has the most expensive retail price of electricity in the country.

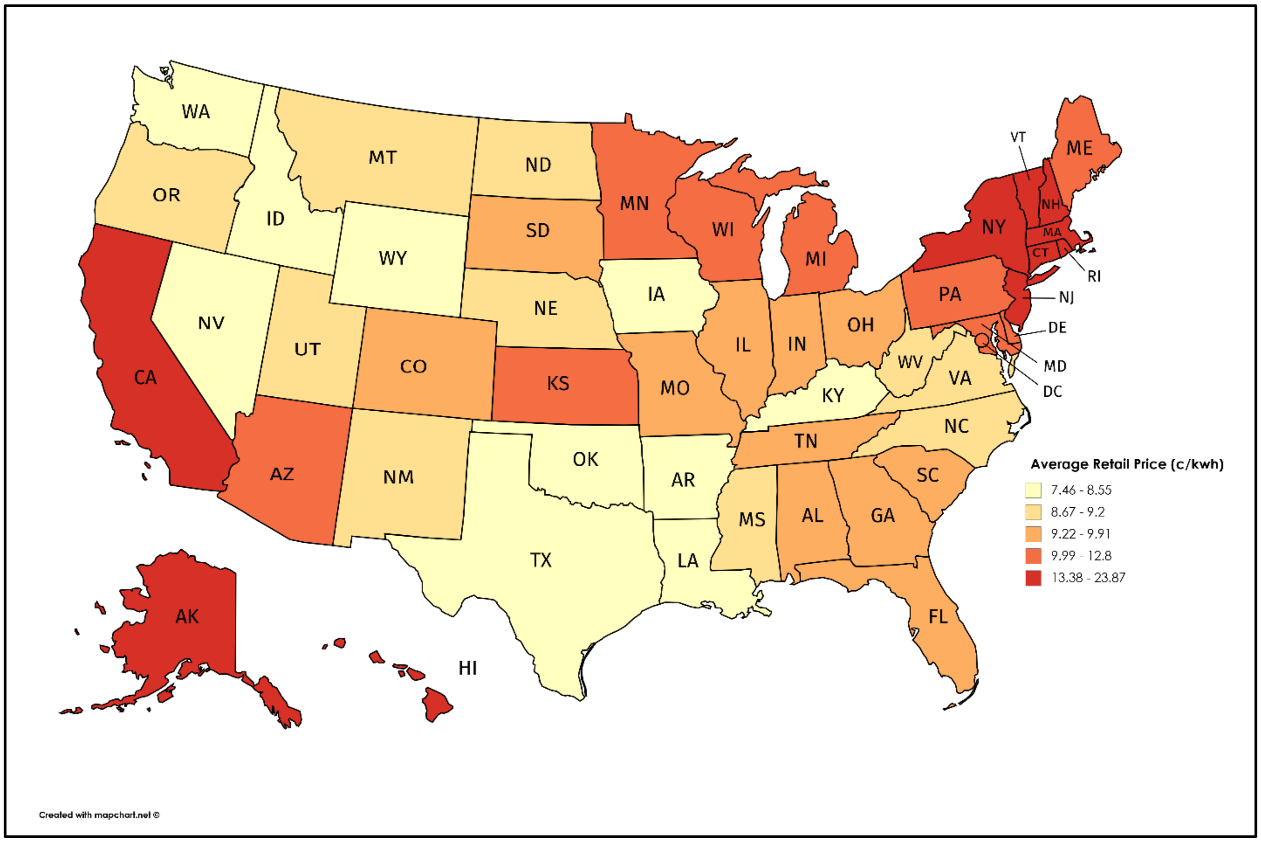

Figure 2-6 Average Retail Electricity Price by State (cents/kWh), 2016
Source: EIA State Electricity Profiles 2016 (https://www.eia.gov/electricity/state/) Accessed March 2018.

Average national overall retail electricity prices increased between 2006 and 2016 by 15.4 percent in nominal (current year $) terms. The amount of increase differed for the three major end use categories (i.e., residential, commercial and industrial). As seen in Figure 2-8, national average residential prices increased the most (20.7 percent), and commercial prices increased the least (10.3 percent). The nominal year prices for 2006 through 2016 are shown in Figure 2-7.

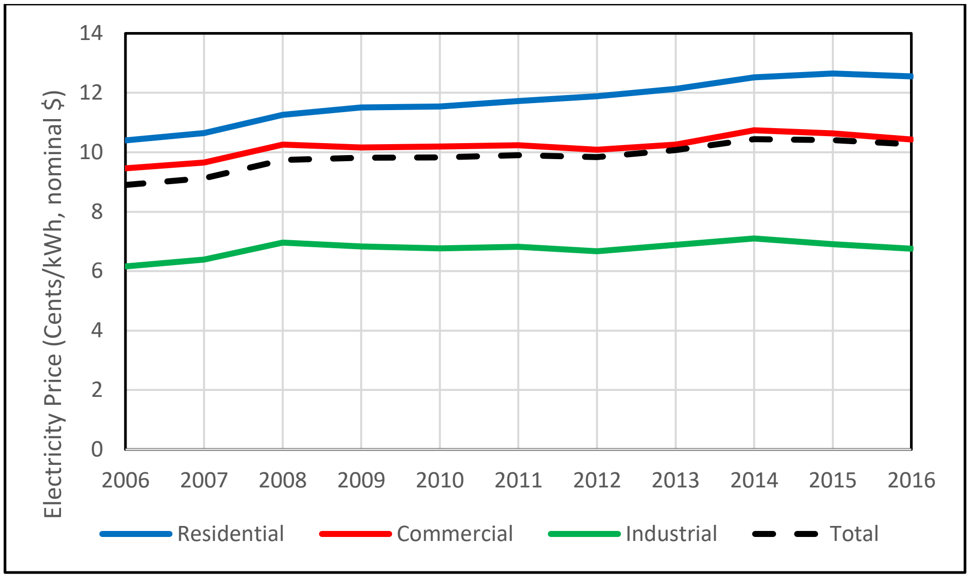

Figure 2-7 Nominal National Average Electricity Prices for Three Major End-Use Categories

Source: EIA 861, Table 3.4

Electricity prices for the commercial and industrial end-use categories did not increase more than overall inflation through this period, measured by either the GDP implicit price deflator (17.5 percent) or the consumer price index (CPI-U, which increased by 19.1 percent).[6] The increase in nominal electricity prices for the major end use categories, as well as increases in the GDP price and CPI-U indices for comparison, are shown in Figure 2-8.

[6] Source: Federal Reserve Economic Data, FRB St. Louis. Available online at: http://research.stlouisfed.org/fred2/.

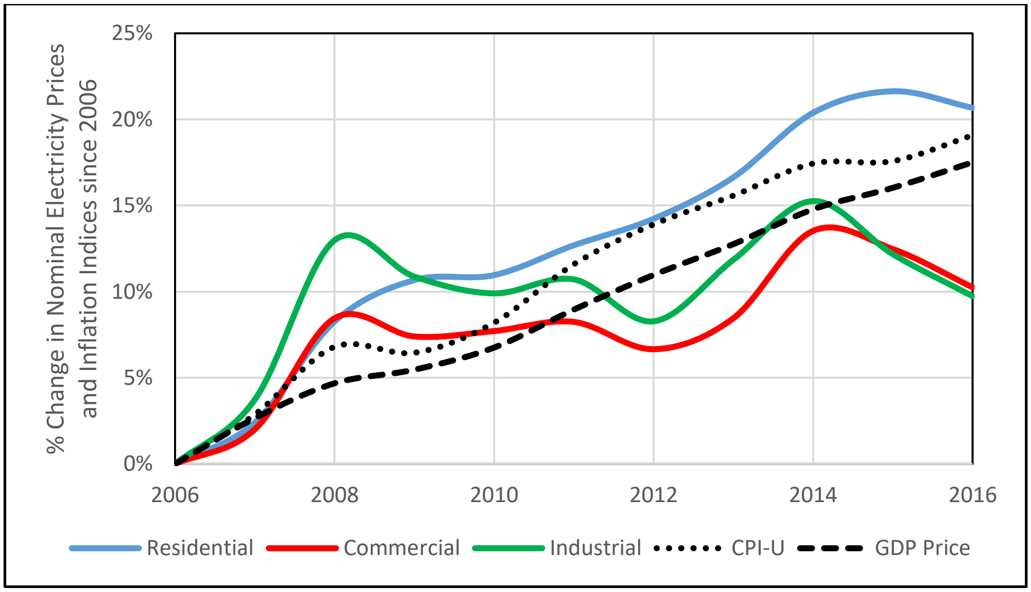

Figure 2-8 Relative Increases in Nominal National Average Electricity Prices for Major End-Use Categories, With Inflation Indices

Source: EIA 861, Table 3.4

The real (inflation-adjusted) change in average national electricity prices can be calculated using the GDP implicit price deflator. Figure 2-9 shows real[7] (2016$) electricity prices for the three major customer categories from 1960 to 2016, and Figure 2-10 shows the relative change in real electricity prices relative to the prices in 1960. As can be seen in the figures, the price for industrial customers has always been lower than for either residential or commercial customers, but the industrial price has been more volatile. While the industrial real price of electricity in 2016 was relatively unchanged from 1960, residential and commercial real prices are 24 percent and 32 percent lower respectively than in 1960.

[7] All prices in this section are estimated as real 2016 prices adjusted using the GDP implicit price deflator unless otherwise indicated.

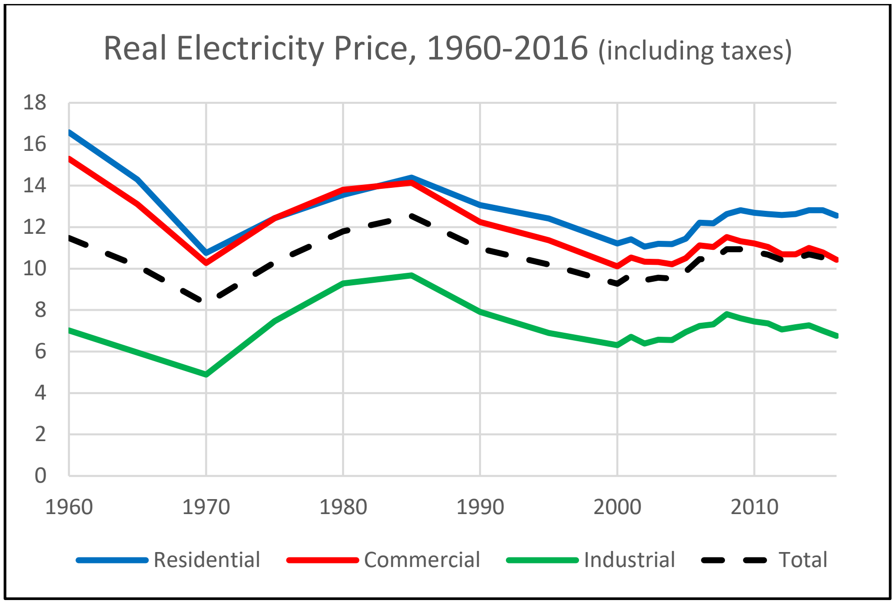

Figure 2-9 Real National Average Electricity Prices (2016$) for Three Major End-Use Categories

Source: EIA Monthly Energy Review, Dec. 2017, Table 9.8

Notes: Price data is five-year averages for 1960 through 2000, and annual from 2016 through 2016.

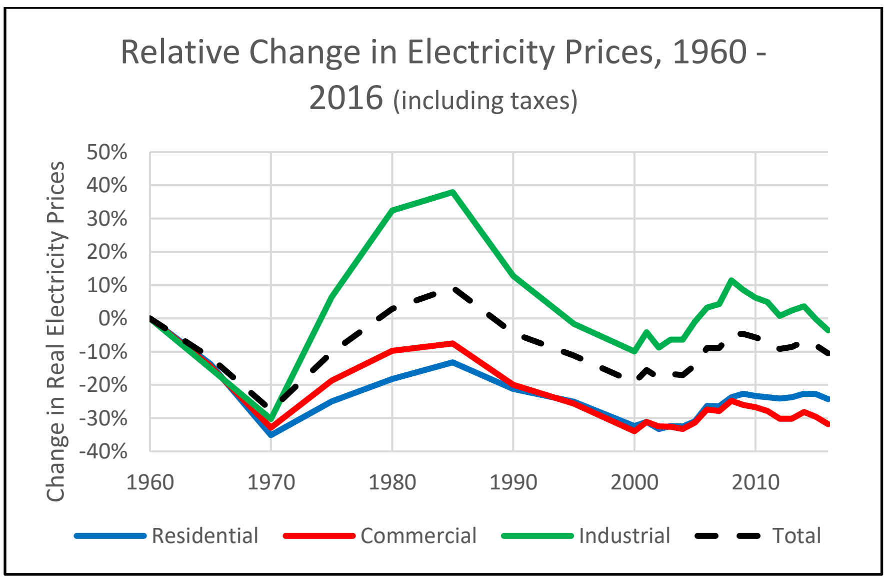

Figure 2-10 Relative Change in Real National Average Electricity Prices (2016) for Three Major End-Use Categories

Source: EIA Monthly Energy Review, Dec. 2017, Table 9.8

Notes: Price data is five-year averages for 1960 through 2000, and annual from 2016 through 2016.

2.3.2 Prices of Fossil Fuels Used for Generating Electricity

Another important factor in the changes in electricity prices are the changes in fuel prices for the three major fossil fuels used in electricity generation; coal, natural gas and oil. Relative to real prices in 2006, the national average real price (in 2016$) of coal delivered to EGUs in 2016 had increased by 6.2 percent, while the real price of natural gas decreased by 65 percent. The real price of oil decreased by 28 percent. The combined real delivered price of all fossil fuels in 2016 decreased by 30 percent over 2006 prices. Figure 2-11 shows the relative changes in real price of all 3 fossil fuels between 2006 and 2016.

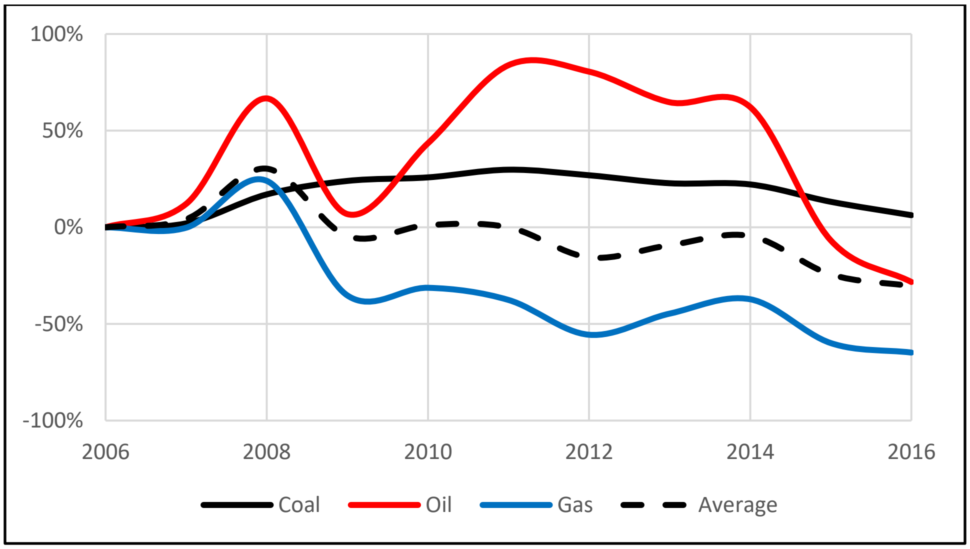

Figure 2-11 Change in National Annual Average Cost of Real Fossil Fuel Receipts at EGUs per MMBtu

Source: EIA Monthly Energy Review Dec. 2017, Table 9.9
Note: Costs include taxes.

2.3.3 Changes in Electricity Intensity of the U.S. Economy

An important aspect of the changes in electricity generation (i.e., electricity demand) between 2006 and 2016 is that while total net generation increased by less than 1 percent over that period, the demand growth for generation has been low, and in fact was lower than both the population growth (8.4 percent) and real GDP growth (14 percent). Figure 2-12 shows the growth of electricity generation, population and real GDP during this period.

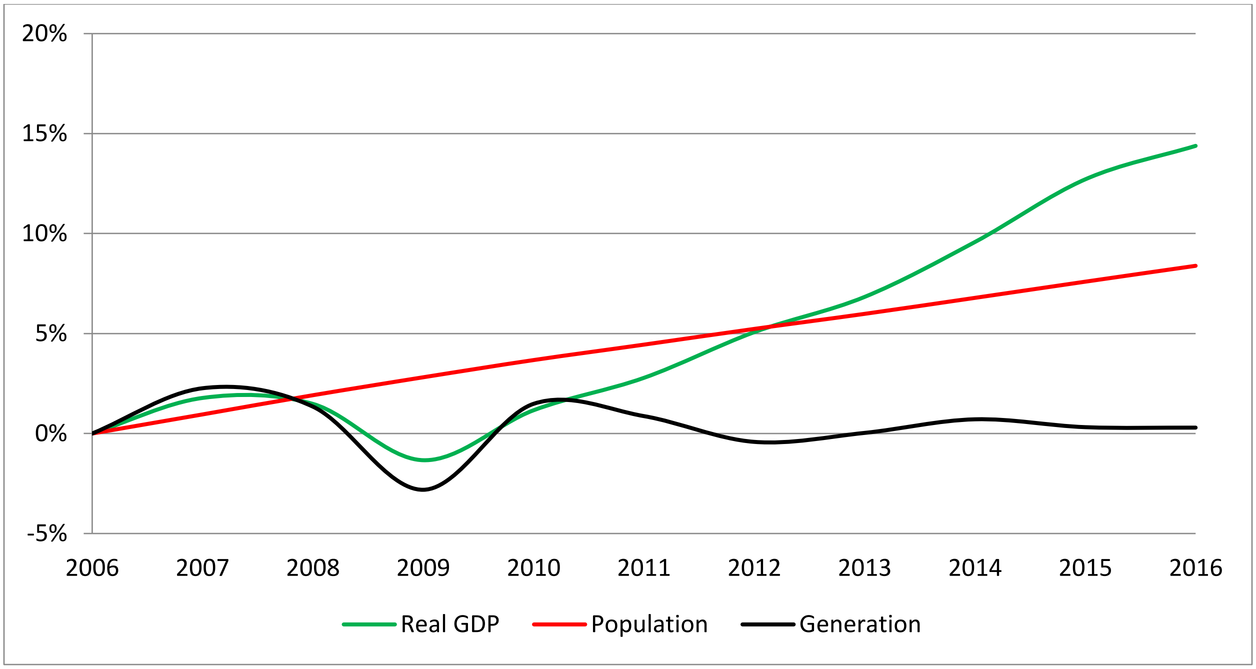

Figure 2-12 Relative Growth of Electricity Generation, Population and Real GDP Since 2006

Sources: U.S. EIA Monthly Energy Review, March 2018. Table 7.2a Electricity Net Generation: Total (All Sectors). U.S. Census.

Because demand for electricity generation grew more slowly than both the population and GDP, the relative electric intensity of the U.S. economy improved (i.e., less electricity used per person and per real dollar of output) during 2006 to 2016. On a per capita basis, real GDP per capita grew by 5.53 percent, increasing from $48,977 (in 2016$) per person in 2006 to $51,688/person in 2016. At the same time electricity generation per capita decreased by 7.14 percent, declining from 0.014 MWh/person in 2006 to 0.013 MWh/person in 2016. The combined effect of these two changes improved the overall electricity efficiency of the U.S. market economy. Electricity generation per dollar of real GDP decreased 12.3 percent, declining from 278 MWh per $1 million of GDP to 244 MWh/$1 million GDP. These relative changes are shown in Figure 2-13. Figure 2-12 and Figure 2-13 clearly show the effects of the 2007 – 2009 recession on both GDP and electricity generation, as well as the effects of the subsequent economic recovery.

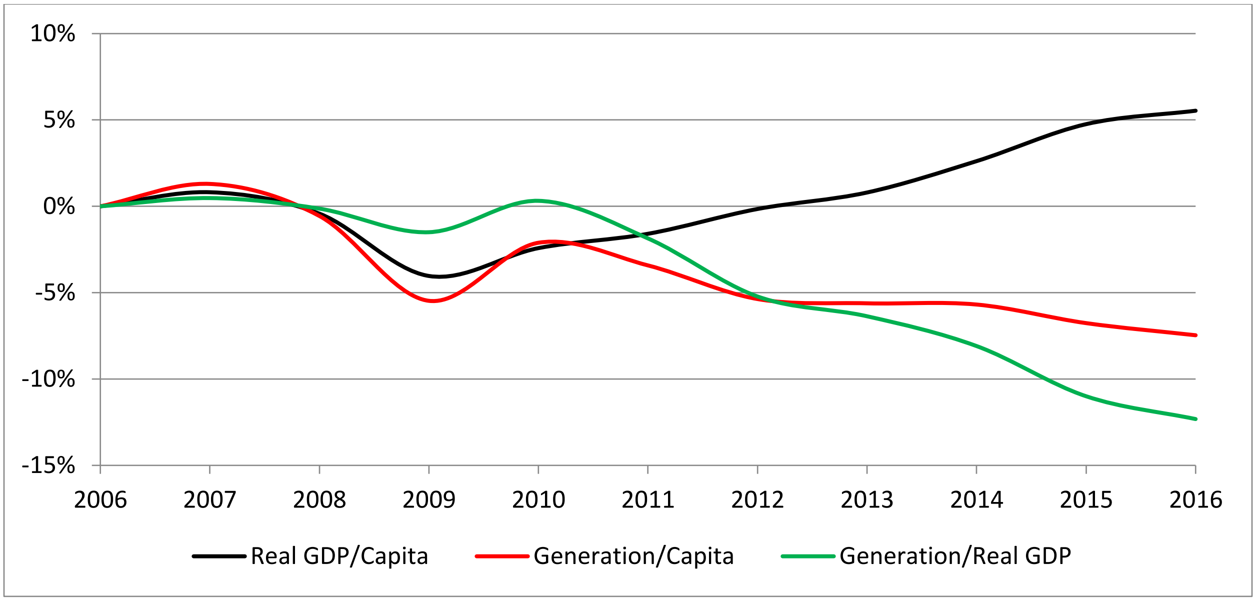

Figure 2-13 Relative Change of Real GDP, Population and Electricity Generation Intensity Since 2006

Sources: U.S. EIA Monthly Energy Review, March 2018. Table 7.2a Electricity Net Generation: Total (All Sectors). U.S. Census

2.4 Deregulation and Restructuring

The process of restructuring and deregulation of wholesale and retail electric markets has changed the structure of the electric power industry. In addition to reorganizing asset management between companies, restructuring sought a functional unbundling of the generation, transmission, distribution, and ancillary services the power sector has historically provided, with the aim of enhancing competition in the generation segment of the industry.

Beginning in the 1970s, government policy shifted against traditional regulatory approaches and in favor of deregulation for many important industries, including transportation (notably commercial airlines), communications, and energy, which were all thought to be natural monopolies (prior to 1970) that warranted governmental control of pricing. However, deregulation efforts in the power sector were most active during the 1990s. Some of the primary drivers for deregulation of electric power included the desire for more efficient investment choices, the economic incentive to provide least-cost electric rates through market competition, reduced costs of combustion turbine technology that opened the door for more companies to sell power with smaller investments, and complexity of monitoring utilities' cost of service and establishing cost based rates for various customer classes. Deregulation and market restructuring in the power sector involved the divestiture of generation from utilities, the formation of organized wholesale spot energy markets with economic mechanisms for the rationing of scarce transmission resources during periods of peak demand, the introduction of retail choice programs, and the establishment of new forms of market oversight and coordination.

The pace of restructuring in the electric power industry slowed significantly in response to market volatility in California and financial turmoil associated with bankruptcy filings of key energy companies. Currently, restructuring has been suspended in California, (shown as "Suspended" in Figure 2-14). Twenty-six other states are not considering restructuring at this time (Figure 2-14). Currently, there are 13 states plus the District of Columbia that allow retail access (Figure 2-14). Power sector restructuring is more or less at a standstill; by 2010 there were no active proposals under review by the Federal Energy Regulatory Commission (FERC) for actions aimed at wider restructuring, and no additional states have begun retail deregulation activity since that time.

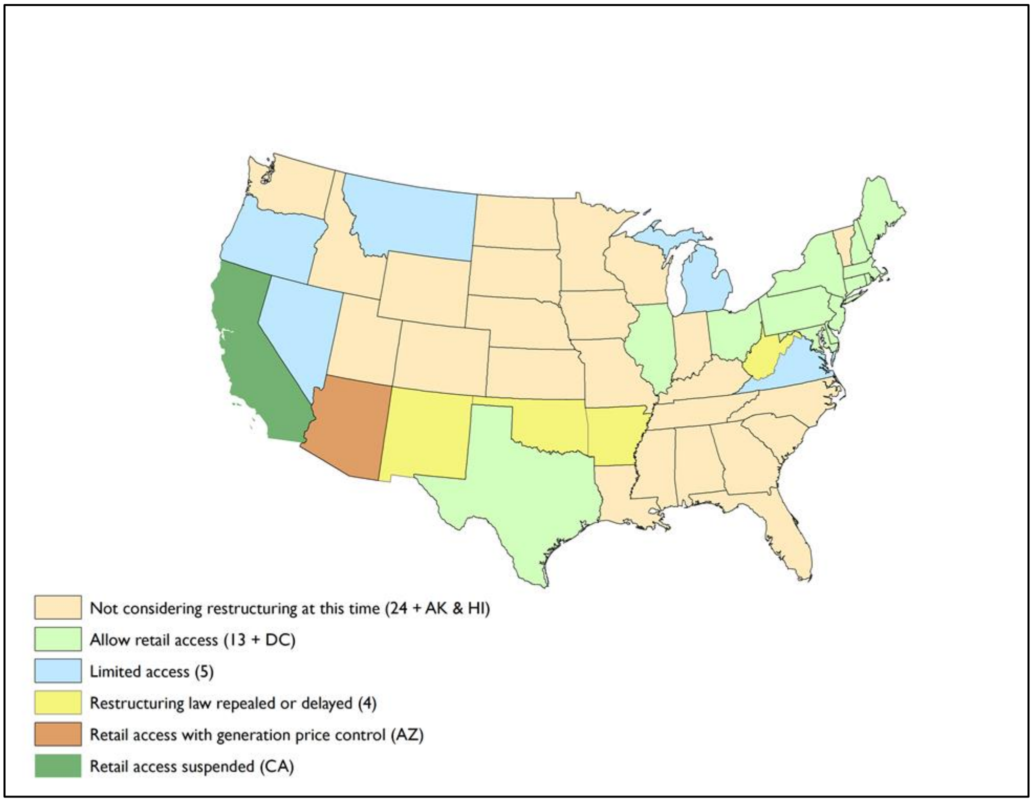

Figure 2-14 Status of State Electricity Industry Restructuring Activities

Source: Map adapted from Rose, Ken. 2017. *Retail Electricity Markets.* 59th Annual Regulatory Studies Program Institute of Public Utilities, Michigan State University.

One major effect of the restructuring and deregulation of the power sector was a significant change in type of ownership of electricity generating units in the states that deregulated prices. Throughout most of the 20th century, electricity was supplied by vertically integrated regulated utilities. The traditional integrated utilities generation, transmission and distribution in their designated areas, and prices were set by cost of service regulations set by state government agencies (e.g., Public Utility Commissions). Deregulation and restructuring resulted in unbundling of the vertical integration structure. Transmission and distribution continued to operate as monopolies with cost of service regulation, while generation shifted to a mix of ownership affiliates of traditional utility ownership and some generation owned and operated by competitive companies known as Independent Power Producers (IPP). The resulting generating sector differed by state or region, as the power sector adapted to the restructuring and deregulation requirements in each state.

By 2006 the major impacts of adapting to changes brought about by deregulation and restructuring during the 1990s were largely in place. The resulting ownership mix of generating capacity (MW) in 2006 was about 58 percent of the generating capacity owned by traditional utilities, 39 percent owned by IPPs[8], and 3 percent owned by commercial and industrial producers. The mix of electricity generated (MWh) was more heavily weighted towards the utilities, with a distribution in 2006 of 66 percent, 30 percent and 4 percent for utilities, IPPs and commercial/industrial, respectively.

Since 2006 IPPs have expanded faster than traditional utilities, substantially increasing their share by 2016 of both capacity (56 percent utility, 41 percent IPPs, and 3 percent commercial/industrial) and generation (58 percent utility, 38 percent IPPs, and 4 percent commercial/industrial).

The mix of capacity and generation for each of the ownership types is shown in Figure 2-15 (capacity) and Figure 2-16 (generation). The capacity and generation data for commercial and industrial owners are not shown on these figures due to the small magnitude of those ownership types. Figure 2-15 and Figure 2-16 present the mixes in 2006 and 2016. Traditional utilities have expanded capacity in gas, and IPPs have increased their capacity in wind. Both traditional utilities and IPPs have markedly reduced their generation from coal and increased their generation from wind between 2006 and 2016.

[8] IPP data presented in this section include both combined and non-combined heat and power plants.

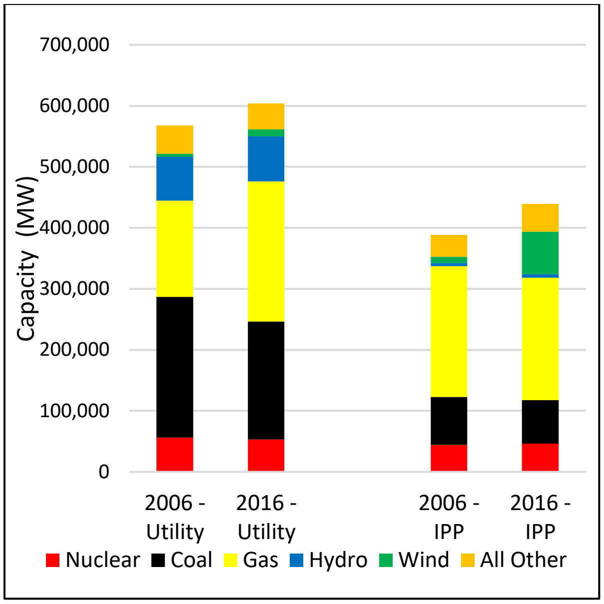

Figure 2-15 Capacity Mix by Ownership Type, 2006 & 2016

Source: Electric Power Annual 2016 (Released December 7, 2017) (https://www.eia.gov/electricity/annual/)

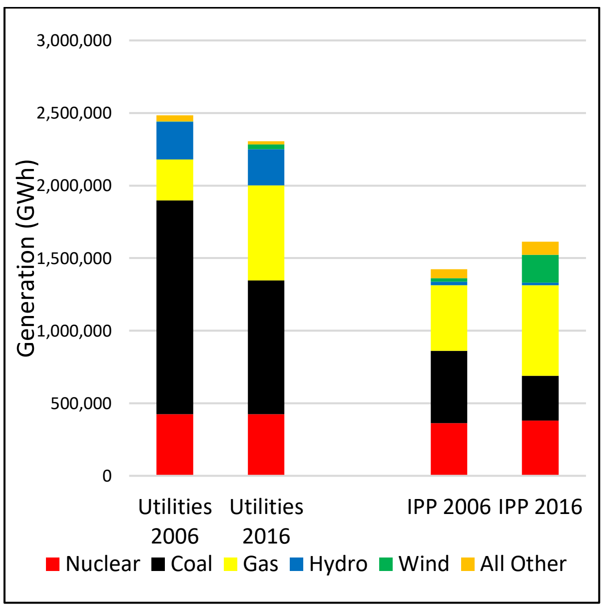

Figure 2-16 Generation Mix by Ownership Type, 2006 & 2016

Source: Electric Power Annual 2016 (Released December 7, 2017) (https://www.eia.gov/electricity/annual/)

The mix of capacity by fuel types that have been built and retired between 2006 and 2016 also varies significantly by type of ownership. Figure 2-17 presents the new capacity built during that period, showing that IPPs built the majority of both new wind and solar generating capacity, but significantly less natural gas capacity than the traditional utilities built. Figure 2-18 presents comparable data for the retired capacity, showing that utilities retired more coal and "other" capacity (mostly residual fuel oil) than IPPs retired, while the IPPs retired more natural gas capacity than the utilities retired.

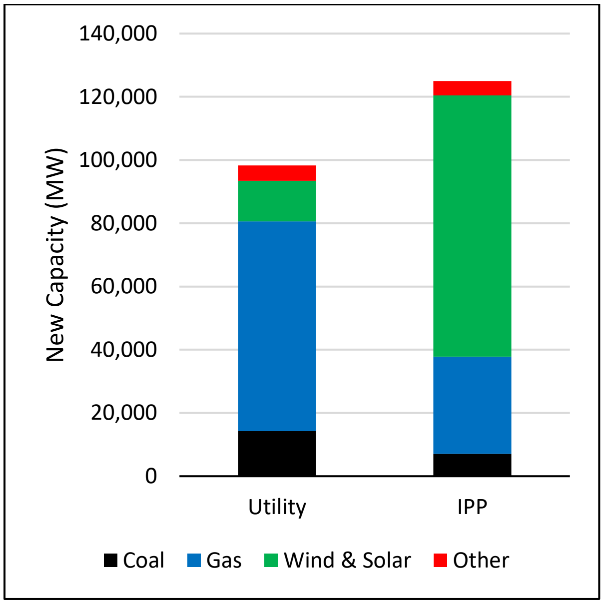

Figure 2-17 Generation Capacity Built between 2006 and 2016 by Ownership Type
Sources: EIA Form 860 (2016)

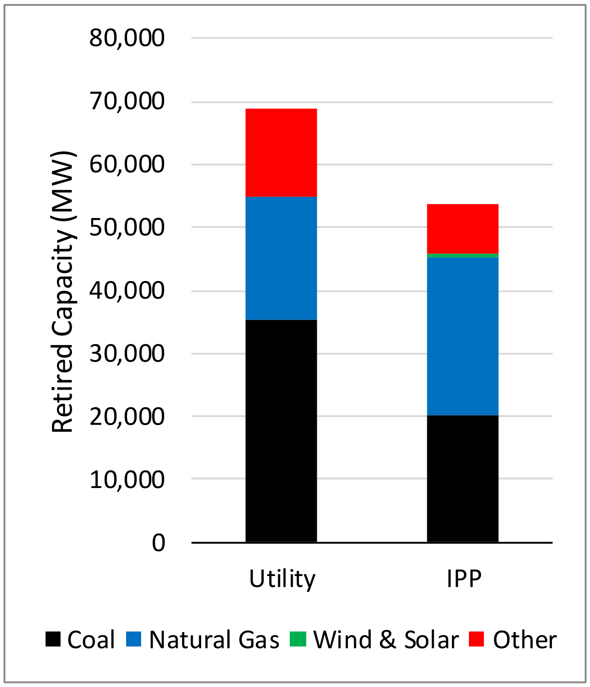

Figure 2-18 Generation Capacity Retired between 2006 and 2016 by Ownership Type
Sources: EIA Form 860 (2016)

2.5 Emissions of Greenhouse Gases from Electric Utilities

The burning of fossil fuels, which generates about 65 percent of our electricity nationwide, results in emissions of greenhouse gases. The power sector is a major contributor of CO_2 in particular, but also contributes to emissions of sulfur hexafluoride (SF_6), CH_4, and N_2O. Including both generation and transmission (a source of SF_6), the power sector accounted for 29 percent of total nationwide greenhouse gas emissions, measured in CO_2 equivalent. Table 2-5 and Figure 2-19 show the GHG emissions[9] from the power sector relative to other major economic sectors. Table 2-6 shows the contributions of CO_2 and other GHGs towards total power sector GHG emissions.

[9] CO_2 equivalent data in this section are calculated with the IPCC SAR (Second Assessment Report) GWP potential factors.

Table 2-5 Domestic Emissions of Greenhouse Gases, by Economic Sector (million tons of CO_2 equivalent)

Sector/Source	2006		2015		Change Between '06 and '15		
	GHG Emissions	% Total GHG Emissions	GHG Emissions	% Total GHG Emissions	Change in Emissions	% Change in Emissions	% of Total Change in Emissions
Electric Power Industry	2,629	33%	2,140	29%	-489	-19%	67%
Transportation	2,199	28%	1,991	27%	-207	-9%	29%
Industry	1,652	21%	1,556	21%	-96	-6%	13%
Agriculture	646	8%	629	9%	-18	-3%	2%
Commercial	427	5%	482	7%	55	13%	-8%
Residential	370	5%	411	6%	41	11%	-6%
US Territories	65	1%	51	1%	-14	-21%	2%
Total GHG Emissions	7,988	100%	7,260	100%	-727	-9%	100%
Sinks and Reductions	-817		-837		-20	2%	
Net GHG Emissions	7,171		6,424		-747	-10%	

Source: EPA, 2017 "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2015", Table 3-10. Includes CO_2, CH_4, N_2O and SF_6 emissions.

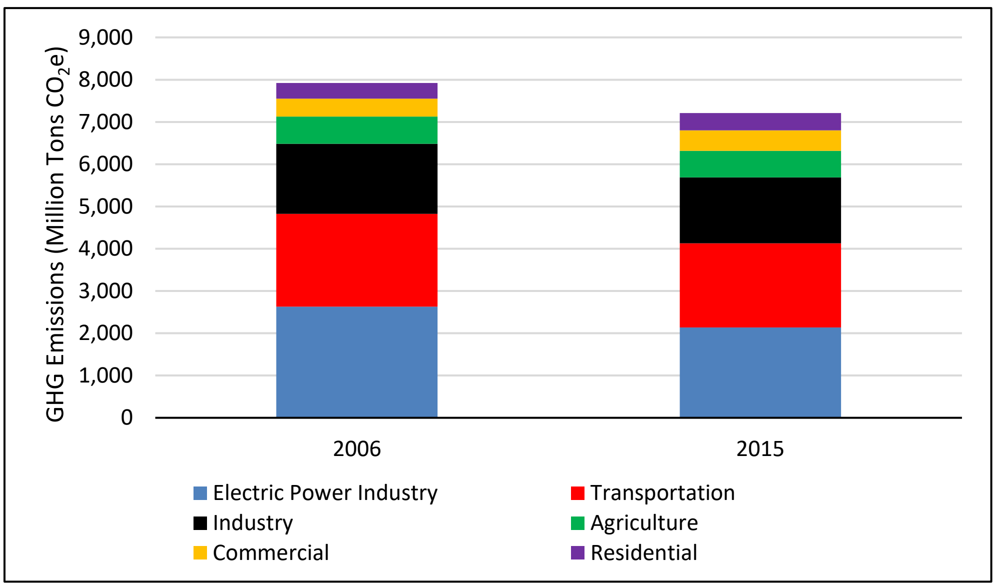

Figure 2-19 Domestic Emissions of Greenhouse Gases from Major Sectors, 2006 and 2015 (million tons of CO_2 equivalent)

Source: EPA, 2017 "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2015", Table 3-10.
Not Shown: CO_2e emissions from US Territories

The amount of CO_2 emitted during the combustion of fossil fuels varies according to the carbon content and heating value of the fuel used. Coal has higher carbon content than oil or natural gas, and thus releases more CO_2 during combustion. Coal emits around 1.7 times as much carbon per unit of energy when burned as natural gas (EPA 2013).

Table 2-6 Greenhouse Gas Emissions from the Electricity Sector (Generation, Transmission and Distribution), 2006 and 2015 (million tons of CO_2 equivalent)

Gas/Fuel Type or Source		2006		2015		Change Between '06 and '15	
		GHG Emissions	% of Total GHG Emissions from Power Sector	GHG Emissions	% of Total GHG Emissions from Power Sector	Change in GHG Emissions	% Change in Emissions
CO_2		2,603	99.0%	2,113	98.7%	-490	-19%
	Fossil Fuel Combustion	2,585	98.32%	2,095	97.9%	-490	-19%
	Coal	2,154	81.9%	1,489	69.6%	-665	-31%
	Natural Gas	373	14.17%	580	27.10%	207	56%
	Petroleum	58.6	2.23%	26.1	1.22%	-32.5	-55%
	Geothermal	0.4	0.02%	0.4	0.02%	0.0	0%
	Incineration of Waste	13.8	0.52%	11.8	0.55%	-2.0	-14%
	Other Process Uses of Carbonates	4.0	0.15%	6.2	0.29%	2.2	56%
CH_4		0.6	0.02%	0.4	0.02%	-0.1	-20%
	Stationary Combustion*	0.6	0.02%	0.4	0.02%	-0.1	-20%
	Incineration of Waste	+		+			
N_2O		18.3	0.70%	21.8	1.02%	3.5	19%
	Stationary Combustion*	17.9	0.68%	21.5	1.00%	3.6	20%
	Incineration of Waste	0.4	0.02%	0.3	0.02%	-0.1	-25%
SF_6		7.6	0.29%	4.6	0.22%	-3.0	-39%
	Electrical Transmission and Distribution	7.6	0.29%	4.6	0.22%	-3.0	-39%
Total GHG Emissions		**2,630**		**2,140**		**-490**	

Source: EPA, 2017 "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2015", Table 3-11
* Includes only stationary combustion emissions related to the generation of electricity.
** SF_6 is not covered by this rule, which specifically regulates GHG emissions from combustion.
+ Does not exceed 0.05 Tg CO_2 Eq. or 0.05 percent.

2.6 Revenues and Expenses

Total utility operating revenues have moderately increased from about $275 billion in 2006 to about $282 billion in 2016. With revenues increasing between 2006 and 2016, operating expenses decreased from 2006 to 2016 and as a result, net income increased by over $13 billion between these years (see Table 2-7). While real electricity prices have generally declined and net generation has remained relatively stable over the last several years, utilities' net income has increased as operating expenses have decreased over the same time period due to declines in fossil fuel prices to utilities.

Table 2-7 shows that investor-owned utilities (IOUs) earned income of about 15.4 percent compared to total revenues in 2016. The 2016 return on revenue was the highest year for the period 2006 to 2016 (average: 12.4 percent range: 10.6 percent to 15.4 percent).

Table 2-7 Revenue and Expense Statistics for Major U.S. Investor-Owned Electric Utilities for 2006, 2011 and 2016 (nominal $millions)

	2006	2011	2016
Utility Operating Revenues	**275,501**	**280,520**	**282,499**
Electric Utility	246,736	255,573	261,047
Other Utility	28,765	24,946	21,451
Utility Operating Expenses	**245,589**	**247,118**	**239,037**
Electric Utility	218,445	228,873	226,457
Operation	158,893	161,460	145,077
Production	127,494	122,520	100,852
Cost of Fuel	37,945	42,779	32,621
Purchased Power	79,205	61,447	49,962
Other	10,371	18,294	18,269
Transmission	6,179	6,876	10,447
Distribution	3,640	4,044	4,734
Customer Accounts	4,409	5,180	5,077
Customer Service	2,536	5,311	6,187
Sales	240	185	205
Admin. and General	14,580	17,343	17,575
Maintenance	12,838	15,772	16,982
Depreciation	17,373	22,555	30,097
Taxes and Other	28,149	29,086	34,301
Other Utility	27,143	18,245	12,579
Net Utility Operating Income	**29,912**	**33,402**	**43,462**

Source: Table 8.3, EIA Electric Power Annual, 2016
Note: This data does not include information for public utilities, nor for Independent Power Producers (IPPs).

2.7 Natural Gas Market

The natural gas market in the United States has historically experienced significant price volatility from year to year, between seasons within a year, can undergo major price swings during short-lived weather events (such as cold snaps leading to short-run spikes in heating demand), and has seen a dramatic shift since 2008 due to increased production from shale formations. Over the last decade, the annual average nominal price of gas delivered to the power sector peaked in 2008 at $9.02/MMBtu and has since fallen dramatically to a low of

$2.87/MMBtu in 2016. During that time, the daily price[10] of natural gas reached as high as $18.48/MMBtu and as low as $1.05. Adjusting for inflation using the GDP implicit price deflator in 2016$, the annual average price of natural gas delivered to the power sector peaked at $10.13/MMBtu in 2008 and has fallen dramatically to a low of $2.87 in 2016. The annual natural gas prices in both nominal and real (2016$) terms are in Figure 2-20 and Figure 2-21. A comparison of the trends in the real price of natural gas with the real prices of delivered coal and oil are shown in Figure 2-21. Figure 2-21 shows that while the real price of coal increased by 6 percent and oil decreased by 28 percent from 2006 to 2016, the real price of natural gas declined by 65 percent in the same period. Most of the decline in real natural gas prices occurred between 2008 (the peak price year) and 2012, during which real gas prices declined by 64 percent while coal and oil prices both increased by slightly over 8 percent. The sharp decline in natural gas prices from 2008 to 2012 was primarily caused by the rapid increase in natural gas production from shale formations.

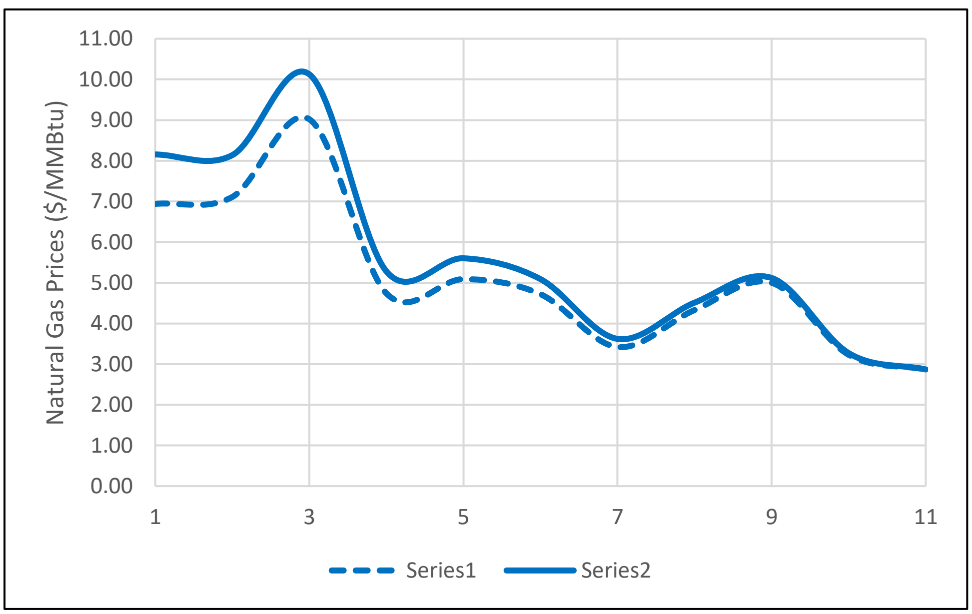

Figure 2-20 Relative Change Nominal and Real (2016$) Prices of Natural Gas Delivered to the Power Sector ($/MMBtu)

Source: EIA, Electric Power Annual, 2016, Table 7.4

[10] Henry Hub daily prices. Henry Hub is a major gas distribution hub in Louisiana; Henry Hub prices are generally seen as the primary metric for national gas prices for all end uses. The price of natural gas delivered to electricity generation differs substantially in different regions of the country, and can be higher or lower than the Henry Hub national benchmark price.

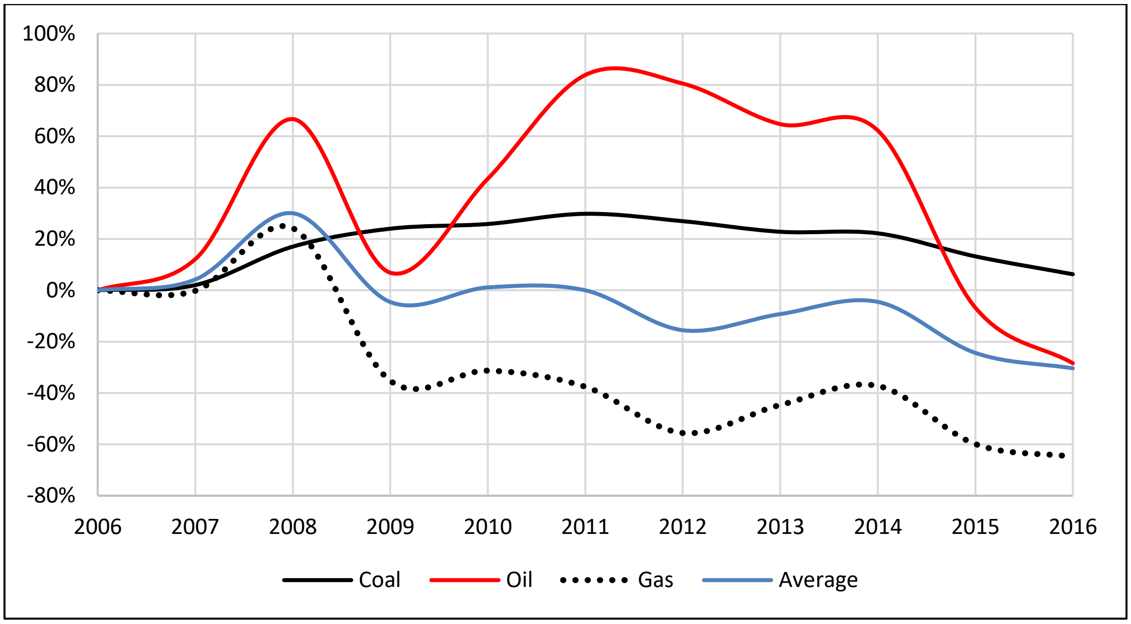

Figure 2-21 Relative Change in Real (2016$) Prices of Fossil Fuels Delivered to the Power Sector ($/MMBtu)

Source: EIA, Electric Power Annual, 2016, Table 7.4

Current and projected natural gas prices are considerably lower than the prices observed over the past decade, largely due to advances in hydraulic fracturing and horizontal drilling techniques that have opened up new shale gas resources and substantially increased the supply of economically recoverable natural gas.

The U.S. Energy Information Administration's (EIA) Annual Energy Outlook (AEO) 2018 estimates that the United States possessed 2,462 trillion cubic feet (Tcf) of technically recoverable dry natural gas resources as of January 1, 2016. At the 2017 rate of U.S. consumption (about 27.5 Tcf per year), the 2,462 Tcf of technically recoverable dry natural gas reserves would be enough to supply more than 90 years of use.

Technically recoverable reserves include proved reserves and unproved resources. Proved reserves of crude oil and natural gas are the estimated volumes expected to be produced, with reasonable certainty, under existing economic and operating conditions. Unproved resources of crude oil and natural gas are additional volumes estimated to be technically recoverable without consideration of economics or operating conditions, based on the application of current technology. Proven reserves make up 12 percent of the technically recoverable total estimate, with the remaining 88 percent from unproven reserves.

2.8 References

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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 proposed 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 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 proposed rule to replace the Clean Power Plan.[2] The proposed rule presents a framework for states to develop state plans that will establish standards of performance for existing affected sources of GHG emissions. The proposed 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 may choose to rely upon as they develop standards of performance and State plans. The specific technology options that might be used to establish a standard of performance for individual affected sources are unknown. Affected sources may not be able to apply the technology options because they have already adopted these technologies, they are not applicable to the source, or for other reasons. The rule also re-proposes reforms to New Source Review (NSR) that may facilitate the application of HRI technologies from the BSER to sources that the States otherwise may have deemed inapplicable to those sources as part of their state plans.

For these reasons, there is considerable uncertainty regarding the specific technology measures that might be applied by States from the BSER across the universe of affected sources,

[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.

and the subsequent standard of performance that will result from that process. Hence, this analysis presents illustrative scenarios that are intended to broadly reflect how States might apply BSER and develop state plans, and are intended to inform and present the potential impacts of the proposed rule. Each illustrative scenario assigns the same average percentage HRI and associated average capital cost to each affected coal steam unit in the contiguous U.S.[4] The analysis *is not* meant to reflect what EPA believes can be undertaken at each affected source, but rather to estimate potential national impacts by applying controls measures that 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 how BSER might ultimately be implemented by States through a performance standard, EPA believes that this illustrative modeling approach is suitable to inform the potential impacts of the rule from a national perspective.

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.[5] 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. 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. 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.[6] The model

[4] This is consistent with past modeling approaches for CPP and the 316(b) rule regarding Cooling Water Intake, where generic assumptions were used to inform the RIA where more specific unit-level data was lacking.

[5] For more detail on IPM, see model documentation available at https://www.epa.gov/airmarkets/clean-air-markets-power-sector-modeling

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

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 costs presented in this RIA reflect the IPM-projected annualized estimates of private compliance costs.[7] 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.[8] Furthermore, EPA uses the projection of private compliance costs as an estimate of the social cost of the proposed requirements, as the social cost is the appropriate metric for formal economic welfare analysis.[9] 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, 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 present value of all private costs over the full planning horizon while satisfying a wide range of

[7] Where relevant, cost estimates for demand-side energy efficiency improvements are included.

[8] As discussed in further detail in Chapter 5, the ultimate incidence of this proposed action will depend on the distribution of both the costs and the health and welfare impacts presented in Chapter 4 across households.

[9] See, Tietenberg and Lewis, 2008; Freeman, 2003, and USEPA, 2010.

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.

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 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 EPA’s Power Sector Modeling Platform v6 using IPM

In June 2018 EPA updated its application of IPM to version 6. This update incorporates important structural improvements, as well as routine data updates, and reflects a robust representation of electricity generation and related fuel markets. Important improvements/updates include:

- Use of the Energy Information Agency’s (EIA) Annual Energy Outlook (AEO) 2017 demand projections
- Adjustment and increase of model region boundaries to reflect current state of power markets
- Incorporation of three seasons, with additional load segments

- Routine updates to key power sector inputs based on recent data from EIA, NERC, FERC, etc.
- Updated inventory of State and Federal power sector regulations
- Updated transmission representation and regional reserve margins from ISO/RTO NERC Reports
- Updates to 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 life extension costs
- Updated cost and performance characteristics for potential (new) conventional, renewable and nuclear generating units
- Updated wind and solar cost and resource base estimates, capacity credit calculation methodology, hourly generation profiles and time of day based load segments
- Update of cost and performance assumptions for SO_2, NO_X, Hg, HCl and CO_2 emission controls using the most current data available
- Inclusion of cost and performance assumptions for coal-to-gas and HRI technologies
- Update of coal supply curves and transportation matrix
- Natural gas assumptions modeled through annual gas supply curves and IPM region level seasonal basis differentials

More information on these updates is available in the comprehensive model documentation, which is available on EPA's website.[10]

The updated modeling platform incorporates updated data to reflect an evolving power system. Since analysis was conducted in 2015, notable changes have occurred in the industry based on a variety of factors. As a starting point, IPM reflects a detailed snapshot of the current universe of electric generating units throughout the contiguous United States that supply electricity to the grid. This database, called the National Electric Energy Data System (NEEDS), contains an inventory of every unit represented in IPM, summarized below for coal and natural gas-fired sources, including average heat rate data across categories of units. Over the past few years, the power sector has changed notably, with a considerable number of coal-steam power plants coming offline, and increases in natural gas and renewable sources of electricity. For example, the previous iteration of NEEDS that was used during the Final CPP RIA conducted in

[10] See Documentation for 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

2015 showed the total coal-steam capacity to be 269 GW (subtracting known planned retirements from the database at the time of analysis), compared to 226 GW in this updated modeling. This reflects the market trends and changes that have occurred in the power sector over the past few years, where abundant natural gas supplies and low prices, large increases in renewable energy deployment, and flat overall electric demand have all contributed to shifts away from existing coal-fired capacity in the marketplace (See Chapter 2, Industry Profile, for more information on various changes in the power sector over the last decade).

Table 3-1 Coal and Natural Gas Generating Units, by Size, Age, Capacity, and Thermal Efficiency (Heat Rate)

Unit Size Grouping (MW)	No. Units	% of All Units	Avg. Age	Avg. Net Summer Capacity (MW)	Total Net Summer Capacity (MW)	% Total Capacity	Avg. Heat Rate (Btu/kWh)
COAL							
0 – 24	33	6%	57	11	375	0%	12,362
25 – 49	41	7%	41	37	1,499	1%	12,050
50 – 99	39	7%	47	74	2,894	1%	11,929
100 – 149	45	8%	57	122	5,485	2%	11,266
150 – 249	88	15%	54	193	17,013	8%	10,899
250 – 499	140	23%	46	368	51,468	23%	10,605
500 – 749	143	24%	45	609	87,055	39%	10,301
750 – 999	56	9%	42	827	46,293	20%	10,069
1000 - 1500	11	2%	47	1257	13,831	6%	9,802
Total Coal	596	100%	48	379	225,913	100%	10,843
NATURAL GAS							
0 – 24	3950	53%	38	5	20,425	5%	14,144
25 – 49	910	12%	31	41	37,065	9%	11,968
50 – 99	983	13%	30	71	69,749	17%	12,274
100 – 149	371	5%	25	127	47,248	11%	9,116
150 – 249	991	13%	20	178	176,610	43%	8,034
250 – 499	178	2%	16	319	56,727	14%	7,017
500 – 749	7	0.1%	11	549	3,840	1%	6,881
Total Gas	7,390	100%	33	56	411,663	100%	12,377

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

Note: Natural gas includes combustion turbines and combined cycles. The average heat rate reported is the mean of the heat rate of each unit. A lower heat rate indicates a higher level of fuel efficiency. Table is limited to coal-steam units in operation in 2016, and subtracts units with planned retirements prior to 2025. Age is estimated for the year 2025, the first year of analysis.

This analysis reflects the best data available to 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 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 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 proposed 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 Scenarios Analyzed

Several illustrative scenarios were analyzed to estimate potential costs and benefits of the proposed rule. These scenarios represent the CPP, replacement to CPP (this proposal), and No CPP (no Federal regulatory action under CAA Section 111). The following scenarios incorporate the updates discussed in Section 3.4:

- **Base Case Scenario (CPP):** This scenario includes the Clean Power Plan (CPP) modeled in a similar fashion to previous EPA analytical efforts.[11] More specifically, this scenario utilizes a mass-based implementation of CPP at the state level, with intra-state trading covering existing sources only, and no incremental demand-side energy efficiency investments. In this scenario, coal steam units may choose to adopt technologies that achieve a 2.1 percent to 4.3 percent HRI at a capital cost of $100/kW based on prevailing economics, but are not required to do so given the flexible compliance afforded under CPP. The improvement and cost level of HRI in this scenario is consistent with the assumptions regarding the availability and cost of HRI used to develop building block 1 in the final CPP, and is the same level applied in the final RIA for the CPP (U.S. EPA, 2015a). In this RIA, this scenario represents the primary electricity and related fuel market baseline for comparison with the three illustrative policy scenarios below.
- **Illustrative 2 percent HRI at $50/kW Scenario:** This illustrative scenario represents a policy case that reflects modest improvements in HRI absent any revisions to NSR requirements. This scenario assumes a uniform potential HRI is available for all affected sources. In the model, this scenario requires a source to improve its heat rate by 2 percent, at a capital cost of $50/kW. The source can

[11] It is the same general framework and analysis that was used when the CPP was proposed and finalized. The differences include no modeled assumptions to address leakage (such as the New Source Complement or renewable set-aside), allowing banking across modeled years due to new model year configuration, and application of regional heat rate levels at different levels/cost. Heat rate improvements are not applied in an additive manner across any scenario.

either adopt the improvement or retire, based upon the prevailing economics in the model.

- **Illustrative 4.5 percent HRI at $50/kW Scenario:** This illustrative scenario represents a policy case that includes benefits from the proposed revisions to NSR, with the HRI modeled at a low cost. This scenario assumes a uniform potential HRI is available for all affected sources. In the model, this scenario requires a source to improve its heat rate by 4.5 percent, at a capital cost of $50/kW. The source can either adopt the improvement or retire, based upon the prevailing economics in the model.
- **Illustrative 4.5 percent HRI at $100/kW Scenario:** This illustrative scenario represents a policy case that includes the benefits from the proposed revisions to NSR, with the HRI modeled at a higher cost. This scenario assumes a uniform potential HRI is available for all affected sources. In the model, this scenario requires a source to improve its heat rate by 4.5 percent, at a capital cost of $100/kW. The source can either adopt the improvement or retire, based upon the prevailing economics in the model.
- **Illustrative No CPP Scenario:** This illustrative scenario does not apply any standards of performance under section 111(d) of the CAA for CO_2 emissions from existing sources. Furthermore, in this scenario, it is assumed that no source adopts any heat rate improvements.

The year of implementation for the illustrative policy scenarios is 2025, as an approximation for when the standards for performance under the proposed rule might be implemented. The requirements do not change over time. For CPP, the year of implementation is 2023 (the IPM model year that most closely represents the 2022 implementation year of CPP) through 2030 (the CPP emissions requirements hold constant thereafter).

Due to a number of changes in the electricity sector since the CPP was finalized, as documented in the October 2017 RIA proposing to repeal the CPP and Chapter 2 of this RIA, the sector has become less carbon intensive over the past several years, and this trend is projected to continue in the future. These changes and trends are reflected in the modeling used for this analysis. As a result of these changes, the projected compliance costs of achieving the emissions levels required under CPP is now projected to be significantly lower than the estimates presented in the final CPP RIA (U.S. EPA, 2015a).

As discussed above, the proposed regulation requires states to develop standards of performance based on EPA's determination of BSER, which are methods of heat rate improvement 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.[12] In practice, affected sources may have certain flexibilities in how they comply with the standards of performance that differs 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 scenarios representing the proposed 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 proposed rule when applying BSER to avoid retirement of affected sources, and the scenarios do not capture this possibility. However, as discussed in Section 3.7.5, there are relatively few retirements modeled in these scenarios.

The three HRI improvement scenarios reflect a range of technology improvements across the fleet, applied uniformly. Again, 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, EPA used the best available information, research, and analysis to arrive at the assumptions used in these three scenarios.

The primary driver for the difference in HRI level across the scenarios is an assumption pertaining to proposed changes to the New Source Review (NSR) program. In the past, the NSR program has often been cited as an inherent limit on the potential activities, upgrades, and changes that would otherwise be undertaken cost-effectively at particular units, which could result in improved performance and reduced CO_2 emission rates. In this action, EPA proposes certain changes and reforms to the NSR program that are expected to remove regulatory barriers to HRI.[13] This proposed change is the primary driver for including two different levels of HRI to better understand the potential impacts, with the lower level of HRI representing a replacement rule without the NSR regulatory changes, and the higher HRI scenario reflecting a replacement rule that also reflects NSR reform.

[12] 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.
[13] See Chapter 1 for additional information.

The quantity of electricity demanded in each region and model year is assumed to be the same across the base case scenario, which includes the CPP, and the illustrative scenarios described above. An additional scenario was conducted that included CPP with a revised electric demand projection, reflecting end-use energy efficiency measures that were allowed as a compliance option under CPP. This alternative base case scenario is discussed in section 3.8 and compared to the other scenarios that are the focus of this RIA.

3.6 Monitoring, Reporting, and Recordkeeping Costs

EPA projected monitoring, reporting and recordkeeping 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 three illustrative policy scenarios. EPA estimates that would be no incremental MR&R costs under the illustrative No CPP scenario.

In calculating the costs for state entities, EPA estimated personnel costs to oversee compliance, and review and report annually to EPA on program progress relative to meeting the state's reduction goal. To calculate the national costs, EPA estimated that 49 states and 277 facilities would be affected. EPA estimated that the majority of the cost to EGUs would be in calculating net energy output. Since the majority of EGUs do have some energy usage meters or other equipment available to them, EPA believes a new system for calculating net energy output is not needed.

EPA has made it a priority to streamline reporting and monitoring requirements. In this rule, EPA is making implementation as efficient as possible for both the states and the affected EGUs by allowing state plans to utilize 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, 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 EPA's ECMPS there is no additional burden associated with the reporting of that data. Since the ECMPS pathway is already in place, EPA will allow for states to utilize the ECMPS system to facilitate the data reporting of the additional net energy output data required under the emission guidelines. However, because the Acid Rain Program does not require net energy output to be reported, there is some additional burden (Shown in Table 3-2) in updating an affected EGUs monitoring system to be able to report the associated net energy output of an affected EGU.

EPA estimates that it would take three working months for a technician to retrofit any existing energy meters to meet the requirements set in the state plan. Additionally EPA believes that 50 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.[14] Also, after all modifications are made at a facility to measure net energy output, each EGU's Data Acquisition System (DAS) would need to be upgraded to supply the rate-based emissions value to either the state or 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, 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 proposed rule whereby we believe the air office and the energy office will both be involved in performing

[14] 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.

the above-mentioned tasks, we rounded up to the equivalent of two full time staff, which totaled 4,160 hours per year.[15] Table 3-2 presents the estimates of the annual state and industry respondent burden and costs of reporting and recordkeeping for the three illustrative policy scenarios in 2023, 2025, 2030, and 2035.

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	200,237	16.3	0.0	0.04	0.04	16.4
2025	215,639	17.6	0.0	0.02	0.02	17.6
2030	215,639	17.6	0.0	0.02	0.02	17.6
2035	215,639	17.6	0.0	0.02	0.02	17.6
Industry						
2023	154,010	14.1	0.0	0.28	0.28	14.4
2025	0	0.0	0.0	0.00	0.00	0
2030	0	0.0	0.0	0.00	0.00	0
2035	0	0.0	0.0	0.00	0.00	0
Total						
2023	354,247	30.5	0.0	0.31	0.31	30.8
2025	215,639	17.6	0.0	0.02	0.02	17.6
2030	215,639	17.6	0.0	0.02	0.02	17.6
2035	215,639	17.6	0.0	0.02	0.02	17.6

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, as shown in Table 3-2, amounts of labor needed range from approximately 74 FTE for industry in illustrative policy scenario year 2023, to

[15] 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.

approximately 170 FTE for both states and industry in the illustrative policy scenario year 2023, and approximately 104 FTE in policy scenario years 2025, 2030, and 2035.

In the 2015 CPP RIA, EPA projected monitoring, reporting, and recordkeeping costs for both state entities and affected EGUs for the compliance years 2020, 2025, and 2030 (U.S. EPA, 2015a). These estimated costs are applied to the base case for this action, which includes the CPP. As we evaluate MR&R costs for the illustrative policy scenarios in 2023, 2025, 2030, and 2035, it is necessary to compare them against applicable base case MR&R costs in these years. We assume that 2020 MR&R costs from the CPP RIA are applicable to 2023 in the base case for this action. Similarly, we assume that 2030 MR&R costs from the CPP RIA are applicable to 2035 in the base case for this action.

Table 3-3 presents the MR&R costs associated with this action, which is the difference between the cost estimates for the illustrative policy scenario and the MR&R cost estimates for the base case (CPP).

Table 3-3 Years 2025, 2030, and 2035: Total State and Industry Annual Cost of Reporting and Recordkeeping Requirements, Relative to the Base Case (Million 2016$)

	No CPP	2% HRI at $50/kW	4.5% HRI at $50/kW	4.5% HRI at $100/kW
2023	(70.5)	(39.7)	(39.7)	(39.7)
2025	(15.9)	1.7	1.7	1.7
2030	(15.9)	1.7	1.7	1.7
2035	(15.9)	1.7	1.7	1.7

As shown in Table 3-2, almost all MR&R costs are labor costs. Within this category of MR&R, relative to the baseline scenario, Table 3-2 indicates that incremental labor impacts due to monitoring, reporting, and record keeping may range from small negative impacts, e.g. in illustrative policy year 2023 for all four policy options shown in Table 3-2 or all four illustrative years for the "No CPP" option, to small positive impacts in later illustrative policy years (2025, 2030, 2035), for the HRI policy options. In the context of other categories of labor potentially impacted by the rule, such as labor associated with heat rate improvements, 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 scenarios (replacement) to the CPP as the primary comparison point of reference.[16] Other useful comparison points are added, where appropriate.

3.7.1 Projected Emissions

Under the illustrative policy scenarios, EPA projects an annual CO_2 emissions increase in the contiguous U.S. of about 1-2 percent above the base case (CPP) annually in 2025, and 3 percent above the base case (CPP) in 2030 and 2035. For comparison, EPA projects that a full repeal of the CPP would result in an annual CO_2 emissions increase of about 3 percent above the base case (CPP) annually in 2025, and 4 percent above the base case (CPP) in 2030 and 2035. Relative to a projected future without CPP, the illustrative policy scenarios are projected to result in an annual CO_2 emissions decrease of, at most, 2 percent in 2025-2035. Additionally, EPA projects a 2030 CO_2 emissions decrease of 35 percent below 2005 levels for the base case (CPP), and 33 percent below 2005 levels for each of the illustrative policy scenarios.

Table 3-4 Projected CO_2 Emission Impacts, Relative to Base Case (CPP) Scenario

	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
No CPP	1,829	1,811	1,794	50	74	66	3%	4%	4%
Base Case (CPP)	1,780	1,737	1,728	--	--	--	--	--	--
2% HRI at $50/kW	1,816	1,798	1,783	37	61	55	2%	3%	3%
4.5% HRI at $50/kW	1,812	1,797	1,787	32	60	59	2%	3%	3%
4.5% HRI at $100/kW	1,799	1,785	1,772	20	47	44	1%	3%	3%

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

Table 3-5 Projected CO_2 Emission Impacts, Relative to No CPP Scenario

	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
No CPP	1,829	1,811	1,794	--	--	--	--	--	--
Base Case (CPP)	1,780	1,737	1,728	-50	-74	-66	-3%	-4%	-4%
2% HRI at $50/kW	1,816	1,798	1,783	-13	-13	-11	-1%	-1%	-1%
4.5% HRI at $50/kW	1,812	1,797	1,787	-18	-14	-7	-1%	-1%	0%
4.5% HRI at $100/kW	1,799	1,785	1,772	-30	-27	-22	-2%	-1%	-1%

Table 3-6 Projected 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		
	2020	2025	2030	2020	2025	2030	2020	2025	2030
No CPP	1,829	1,811	1,794	-854	-872	-889	-32%	-32%	-33%
Base Case (CPP)	1,780	1,737	1,728	-903	-946	-955	-34%	-35%	-36%
2% HRI at $50/kW	1,816	1,798	1,783	-867	-885	-900	-32%	-33%	-34%
4.5% HRI at $50/kW	1,812	1,797	1,787	-871	-886	-896	-32%	-33%	-33%
4.5% HRI at $100/kW	1,799	1,785	1,772	-884	-898	-911	-33%	-33%	-34%

Under the illustrative policy scenarios, EPA projects a 4 percent increase in SO_2 emissions in 2025, a 5-6 percent increase in SO_2 emissions in 2030, and a 4-5 percent increase in SO_2 emissions in 2035, relative to the base case (CPP). Additionally, EPA projects a 2-3 percent increase in NO_X emissions in 2025, a 4-5 percent increase in 2030, and a 4-6 percent increase in 2035, relative to the base case (CPP). In addition to increases in SO_2 and NO_X emissions, EPA also projects an increase in mercury emissions relative to the base case (CPP): a 2-3 percent increase in 2025, a 4-5 percent increase in 2030, and a 3-4 percent increase in 2035.

Table 3-7 Projected Emissions of SO_2, NO_X, and Hg

	SO_2 (thousand tons)	NO_X (thousand tons)	Hg (tons)
2025			
No CPP	959	874	4.9
Base Case (CPP)	923	842	4.7
2% HRI at $50/kW	959	866	4.9
4.5% HRI at $50/kW	963	863	4.9
4.5% HRI at $100/kW	956	856	4.8
2030			
No CPP	950	833	4.7
Base Case (CPP)	891	786	4.4
2% HRI at $50/kW	943	825	4.6
4.5% HRI at $50/kW	943	825	4.7
4.5% HRI at $100/kW	935	818	4.6
2035			
No CPP	865	783	4.3
Base Case (CPP)	821	740	4.1
2% HRI at $50/kW	855	778	4.2
4.5% HRI at $50/kW	864	782	4.3
4.5% HRI at $100/kW	849	772	4.2

Table 3-8 Percent Change in Projected SO_2, NO_X, and Hg Emissions, Relative to Base Case (CPP) Scenario

	SO_2 (thousand tons)	NO_X (thousand tons)	Hg (tons)
2025			
No CPP	3.9%	3.8%	3.6%
Base Case (CPP)	--	--	--
2% HRI at $50/kW	3.8%	2.8%	3.2%
4.5% HRI at $50/kW	4.3%	2.5%	3.1%
4.5% HRI at $100/kW	3.5%	1.6%	2.3%
2030			
No CPP	6.7%	6.0%	5.4%
Base Case (CPP)	--	--	--
2% HRI at $50/kW	5.9%	5.0%	4.6%
4.5% HRI at $50/kW	5.9%	5.0%	4.9%
4.5% HRI at $100/kW	5.0%	4.1%	4.0%
2035			
No CPP	5.4%	5.9%	4.4%
Base Case (CPP)	--	--	--
2% HRI at $50/kW	4.1%	5.2%	3.5%
4.5% HRI at $50/kW	5.3%	5.8%	4.3%
4.5% HRI at $100/kW	3.5%	4.4%	3.0%

Table 3-9 Percent Difference in Projected SO_2, NO_X, and Hg Emissions, Relative to No CPP Scenario

	SO_2 (thousand tons)	NO_X (thousand tons)	Hg (tons)
2025			
No CPP	--	--	--
Base Case (CPP)	-3.7%	-3.7%	-3.5%
2% HRI at $50/kW	0.0%	-0.9%	-0.4%
4.5% HRI at $50/kW	0.4%	-1.3%	-0.5%
4.5% HRI at $100/kW	-0.3%	-2.1%	-1.3%
2030			
No CPP	--	--	--
Base Case (CPP)	-6.3%	-5.7%	-5.1%
2% HRI at $50/kW	-0.7%	-1.0%	-0.8%
4.5% HRI at $50/kW	-0.7%	-1.0%	-0.5%
4.5% HRI at $100/kW	-1.6%	-1.8%	-1.4%
2035			
No CPP	--	--	--
Base Case (CPP)	-5.1%	-5.5%	-4.2%
2% HRI at $50/kW	-1.2%	-0.6%	-0.9%
4.5% HRI at $50/kW	-0.1%	-0.1%	-0.1%
4.5% HRI at $100/kW	-1.8%	-1.4%	-1.3%

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 base case (CPP) and the three illustrative policy scenarios, including the cost of monitoring, reporting, and recordkeeping (MR&R) costs. 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.[17]

As shown in Table 3-11, EPA projects that the annual compliance costs of the illustrative 2 percent HRI at $50/kW scenario range from roughly no change in 2025, to a $200 million

[17] 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).

avoided cost in 2030, to a $100 million cost in 2035. Under the illustrative 4.5 percent HRI at $50/kW scenario, EPA projects that the annual compliance costs are a $700 million dollar savings in 2025, a $1 billion avoided cost in 2030, and a $600 million avoided cost in 2035, relative to the base case (CPP). Under the illustrative 4.5 percent HRI at $100/kW scenario, EPA projects that the annual compliance costs are $500 million 2025, $200 million in 2030, and $500 million in 2035, relative to the base case (CPP). Results comparing the illustrative scenarios to the No CPP case are shown in Table 3-12. Table 3-10 reports the total generation cost projected by IPM in these five scenarios.

Table 3-10 Total Projected Power Sector System Costs (billions of 2016$)

	2025	2030	2035
No CPP	$144.5	$156.1	$165.2
Base Case (CPP)	$145.2	$156.8	$165.6
2% HRI at $50/kW	$145.3	$156.6	$165.7
4.5% HRI at $50/kW	$144.6	$155.8	$164.9
4.5% HRI at $100/kW	$145.8	$157.0	$166.0

Table 3-11 Annualized Compliance Costs, Relative to Base Case (CPP) Scenario (billions of 2016$)

	2025	2030	2035
No CPP	-$0.7	-$0.7	-$0.4
2% HRI at $50/kW	$0.0	-$0.2	$0.1
4.5% HRI at $50/kW	-$0.6	-$1.0	-$0.6
4.5% HRI at $100/kW	$0.5	$0.2	$0.5

Note: Includes MR&R costs (see 3.6)

Table 3-12 Annualized Compliance Costs, Relative to No CPP Scenario (billions of 2016$)

	2025	2030	2035
Base Case (CPP)	$0.7	$0.7	$0.4
2% HRI at $50/kW	$0.7	$0.5	$0.5
4.5% HRI at $50/kW	$0.1	-$0.2	-$0.2
4.5% HRI at $100/kW	$1.3	$0.9	$0.8

Note: Includes MR&R costs (see 3.6)

3.7.3 Projected Compliance Actions for Emissions Reductions

As discussed above, the illustrative policy scenarios require that all affected sources invest in measures that improve the heat rate performance of each source in order to continue operation or otherwise retire. Some affected sources 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. In the modeling of the illustrative policy scenarios, 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 repeal scenario.[18] See Table 3-13 below for a summary of projected CO_2 emissions by generation sources under each scenario.

Table 3-13 Projected CO_2 Emissions by Generation Source (MM short tons)

	Coal > 25 MW	All Other	Total
2025			
No CPP	1,054	776	1,829
Base Case (CPP)	992	788	1,780
2% HRI at $50/kW	1,048	768	1,816
4.5% HRI at $50/kW	1,051	760	1,812
4.5% HRI at $100/kW	1,039	761	1,799
2030			
No CPP	1,026	786	1,811
Base Case (CPP)	940	797	1,737
2% HRI at $50/kW	1,015	783	1,798
4.5% HRI at $50/kW	1,020	777	1,797
4.5% HRI at $100/kW	1,006	778	1,785
2035			
No CPP	920	874	1,794
Base Case (CPP)	847	882	1,728
2% HRI at $50/kW	912	872	1,783
4.5% HRI at $50/kW	923	864	1,787
4.5% HRI at $100/kW	905	867	1,772

[18] Note that emissions might increase at some generators.

Table 3-14 Projected SO_2 Emissions by Generation Source (thousand short tons)

	Coal > 25 MW	All Other	Total
2025			
No CPP	919	40	959
Base Case (CPP)	880	43	923
2% HRI at $50/kW	919	40	959
4.5% HRI at $50/kW	923	40	963
4.5% HRI at $100/kW	916	40	956
2030			
No CPP	914	37	950
Base Case (CPP)	852	39	891
2% HRI at $50/kW	907	37	943
4.5% HRI at $50/kW	906	38	943
4.5% HRI at $100/kW	898	38	935
2035			
No CPP	837	28	865
Base Case (CPP)	793	28	821
2% HRI at $50/kW	826	28	855
4.5% HRI at $50/kW	836	28	864
4.5% HRI at $100/kW	821	28	849

Table 3-15 Projected NO_X Emissions by Generation Source (thousand short tons)

	Coal > 25 MW	All Other	Total
2025			
No CPP	611	263	874
Base Case (CPP)	569	273	842
2% HRI at $50/kW	606	260	866
4.5% HRI at $50/kW	606	257	863
4.5% HRI at $100/kW	600	256	856
2030			
No CPP	587	246	833
Base Case (CPP)	535	251	786
2% HRI at $50/kW	580	244	825
4.5% HRI at $50/kW	582	243	825
4.5% HRI at $100/kW	575	243	818
2035			
No CPP	523	260	783
Base Case (CPP)	478	262	740
2% HRI at $50/kW	519	259	778
4.5% HRI at $50/kW	524	258	782
4.5% HRI at $100/kW	515	257	772

Table 3-16 Projected Mercury Emissions by Generation Source (short tons)

	Coal > 25 MW	All Other	Total
2025			
No CPP	3.5	1.4	4.9
Base Case (CPP)	3.3	1.4	4.7
2% HRI at $50/kW	3.4	1.4	4.9
4.5% HRI at $50/kW	3.4	1.4	4.9
4.5% HRI at $100/kW	3.4	1.4	4.8
2030			
No CPP	3.3	1.4	4.7
Base Case (CPP)	3.0	1.4	4.4
2% HRI at $50/kW	3.2	1.4	4.6
4.5% HRI at $50/kW	3.3	1.4	4.7
4.5% HRI at $100/kW	3.2	1.4	4.6
2035			
No CPP	2.9	1.4	4.3
Base Case (CPP)	2.7	1.4	4.1
2% HRI at $50/kW	2.9	1.4	4.2
4.5% HRI at $50/kW	2.9	1.4	4.3
4.5% HRI at $100/kW	2.8	1.4	4.2

3.7.4 Projected Generation Mix

Generation by generator type for each of the scenarios is reported in Table 3-17. As can be seen in Table 3-18, the illustrative policy scenarios show an overall increase in generation from the coal steam units covered by this proposed rule. Table 3-19 shows how generation in each of the scenarios differs from the No CPP scenario. Relative to the No CPP scenario, national coal generation is projected to increase between approximately 1 and 5 percent over the time horizon analyzed in this RIA, depending on the assumptions regarding HRI level and cost in each illustrative policy scenario. Figure 3-1 summarizes the information in the tables.

Table 3-17 Projected Generation Mix (thousand GWh)

	No CPP	Base Case (CPP)	2% HRI at $50/kW	4.5% HRI at $50/kW	4.5% HRI at $100/kW
2025					
Coal	962	908	976	1,004	992
NG Combined Cycle (existing)	1,564	1,574	1,552	1,536	1,537
NG Combined Cycle (new)	11	16	12	12	14
Combustion Turbine	38	44	36	34	34
Oil/Gas Steam	63	66	62	65	63
Non-Hydro Renewables	570	575	572	572	574
Hydro	318	320	318	319	319
Nuclear	685	704	682	670	678
Other	37	37	37	37	37
Total	4,248	4,245	4,248	4,248	4,249
2030					
Coal	936	861	944	974	961
NG Combined Cycle (existing)	1,548	1,550	1,542	1,536	1,534
NG Combined Cycle (new)	70	91	72	65	71
Combustion Turbine	40	41	40	38	38
Oil/Gas Steam	60	63	60	62	62
Non-Hydro Renewables	699	722	697	694	695
Hydro	324	325	324	324	324
Nuclear	660	683	658	646	654
Other	36	36	36	36	36
Total	4,374	4,372	4,375	4,375	4,376
2035					
Coal	837	774	846	878	861
NG Combined Cycle (existing)	1,560	1,549	1,554	1,551	1,550
NG Combined Cycle (new)	263	296	266	253	264
Combustion Turbine	57	57	56	54	55
Oil/Gas Steam	66	66	67	69	67
Non-Hydro Renewables	705	728	702	699	700
Hydro	327	327	327	327	327
Nuclear	660	674	658	646	653
Other	37	37	37	37	37
Total	4,512	4,509	4,513	4,514	4,514

Table 3-18 Percent Change in Projected Generation Mix, Relative to Base Case (CPP) Scenario

	No CPP	Base Case (CPP)	2% HRI at $50/kW	4.5% HRI at $50/kW	4.5% HRI at $100/kW
2025					
Coal	5.9%	--	7.4%	10.5%	9.2%
NG Combined Cycle (existing)	-0.6%	--	-1.4%	-2.4%	-2.3%
NG Combined Cycle (new)	-33.1%	--	-24.1%	-29.4%	-11.7%
Combustion Turbine	-13.7%	--	-18.8%	-22.4%	-23.9%
Oil/Gas Steam	-3.8%	--	-5.3%	-1.8%	-4.0%
Non-Hydro Renewables	-0.8%	--	-0.4%	-0.5%	-0.1%
Hydro	-0.7%	--	-0.6%	-0.5%	-0.4%
Nuclear	-2.8%	--	-3.1%	-4.8%	-3.7%
Other	0.0%	--	0.0%	0.0%	0.0%
Total	0.1%	--	0.1%	0.1%	0.1%
2030					
Coal	8.7%	--	9.7%	13.1%	11.6%
NG Combined Cycle (existing)	-0.1%	--	-0.5%	-0.9%	-1.0%
NG Combined Cycle (new)	-22.6%	--	-20.2%	-28.3%	-21.3%
Combustion Turbine	-2.7%	--	-2.6%	-6.4%	-6.7%
Oil/Gas Steam	-4.8%	--	-4.4%	-1.7%	-2.0%
Non-Hydro Renewables	-3.2%	--	-3.4%	-3.9%	-3.8%
Hydro	-0.3%	--	-0.2%	-0.2%	-0.2%
Nuclear	-3.4%	--	-3.7%	-5.5%	-4.3%
Other	0.1%	--	0.1%	0.1%	0.1%
Total	0.0%	--	0.1%	0.1%	0.1%
2035					
Coal	8.1%	--	9.2%	13.4%	11.2%
NG Combined Cycle (existing)	0.7%	--	0.3%	0.1%	0.1%
NG Combined Cycle (new)	-11.2%	--	-10.2%	-14.7%	-10.9%
Combustion Turbine	-0.1%	--	-2.5%	-5.6%	-4.4%
Oil/Gas Steam	-0.6%	--	0.6%	4.0%	0.7%
Non-Hydro Renewables	-3.2%	--	-3.5%	-4.0%	-3.9%
Hydro	0.1%	--	0.1%	0.1%	0.1%
Nuclear	-2.0%	--	-2.4%	-4.1%	-3.0%
Other	0.1%	--	0.2%	0.1%	0.1%
Total	0.1%	--	0.1%	0.1%	0.1%

Table 3-19 Percent Change in Projected Generation Mix, Relative to No CPP Scenario

	No CPP	Base Case (CPP)	2% HRI at $50/kW	4.5% HRI at $50/kW	4.5% HRI at $100/kW
2025					
Coal	--	-5.6%	1.5%	4.4%	3.2%
NG Combined Cycle (existing)	--	0.6%	-0.8%	-1.8%	-1.7%
NG Combined Cycle (new)	--	49.6%	13.5%	5.6%	32.1%
Combustion Turbine	--	15.9%	-5.9%	-10.0%	-11.9%
Oil/Gas Steam	--	4.0%	-1.5%	2.1%	-0.2%
Non-Hydro Renewables	--	0.9%	0.4%	0.3%	0.8%
Hydro	--	0.7%	0.2%	0.2%	0.3%
Nuclear	--	2.9%	-0.3%	-2.1%	-0.9%
Other	--	0.0%	0.0%	0.0%	0.0%
Total	--	-0.1%	0.0%	0.0%	0.0%
2030					
Coal	--	-8.0%	0.9%	4.0%	2.6%
NG Combined Cycle (existing)	--	0.1%	-0.4%	-0.8%	-0.9%
NG Combined Cycle (new)	--	29.2%	3.1%	-7.4%	1.7%
Combustion Turbine	--	2.8%	0.1%	-3.8%	-4.2%
Oil/Gas Steam	--	5.0%	0.4%	3.2%	2.9%
Non-Hydro Renewables	--	3.3%	-0.3%	-0.7%	-0.6%
Hydro	--	0.3%	0.0%	0.0%	0.0%
Nuclear	--	3.5%	-0.3%	-2.1%	-1.0%
Other	--	-0.1%	0.0%	0.0%	0.0%
Total	--	0.0%	0.0%	0.0%	0.0%
2035					
Coal	--	-7.5%	1.0%	4.9%	2.9%
NG Combined Cycle (existing)	--	-0.7%	-0.4%	-0.6%	-0.6%
NG Combined Cycle (new)	--	12.7%	1.1%	-3.8%	0.4%
Combustion Turbine	--	0.1%	-2.4%	-5.6%	-4.3%
Oil/Gas Steam	--	0.6%	1.2%	4.7%	1.3%
Non-Hydro Renewables	--	3.3%	-0.3%	-0.8%	-0.7%
Hydro	--	-0.1%	0.1%	0.0%	0.0%
Nuclear	--	2.1%	-0.3%	-2.1%	-1.0%
Other	--	-0.1%	0.0%	0.0%	0.0%
Total	--	-0.1%	0.0%	0.0%	0.0%

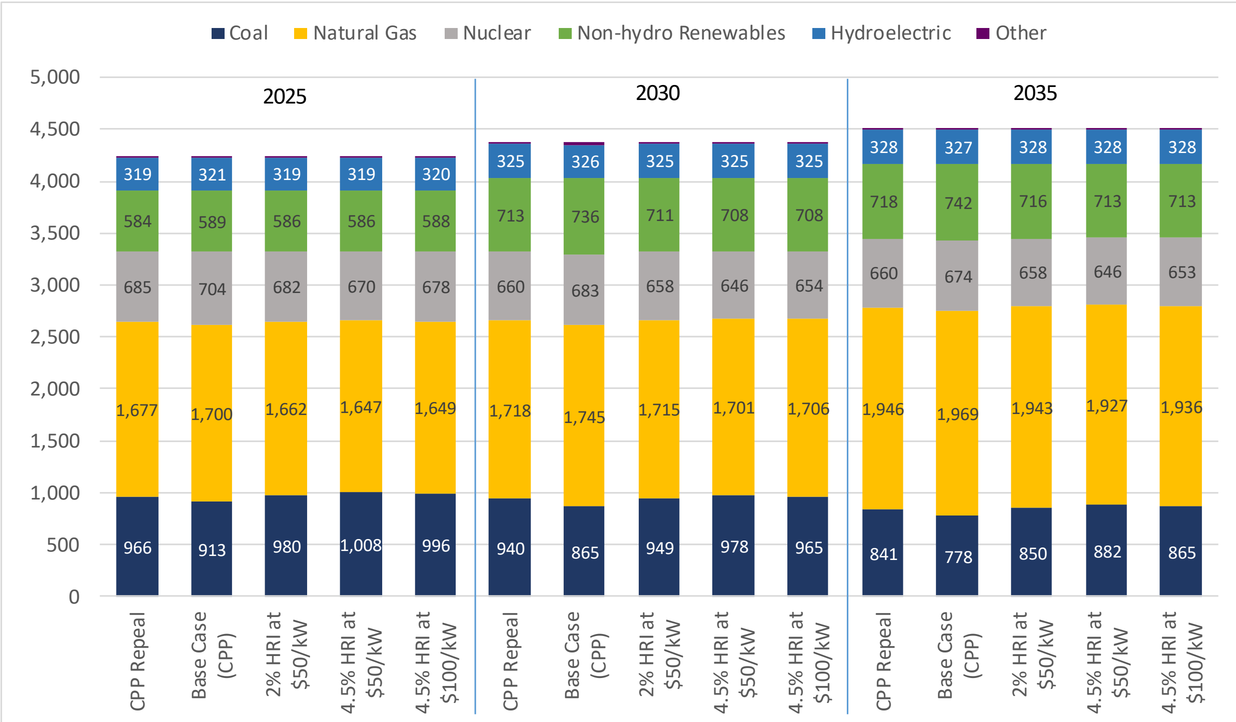

Figure 3-1 Generation Mix (thousand GWh)

3.7.5 Projected Changes to Generating Capacity

Capacity by generator type for each of the scenarios is reported in Table 3-20. As shown in Table 3-21, relative to the base case (CPP), projections of coal capacity are 1-3 percent higher, depending on the illustrative policy scenario. Commensurately, new natural gas combined cycle (NGCC) capacity, new renewable capacity, and existing nuclear capacity are lower in the illustrative scenarios relative to the base case (CPP). Relative to the base case (CPP), EPA projects up to a 30 percent decrease in new NGCC capacity, and a up to a 4 percent decrease in new renewable capacity. The illustrative policy scenarios also result in a projection of additional nuclear capacity retirements, which are projected to result in up to a 6 percent reduction of total nuclear capacity, depending on the illustrative policy scenario. Capacity changes of the various scenarios relative to the No CPP case are reported in Table 3-22. Generally, they show that coal and nuclear capacity is lower in the policy scenarios relative to the repeal scenarios. Table 3-23 through Table 3-26 show the incremental capacity additions over time in the illustrative policy scenarios relative to the base case (CPP) and No CPP scenarios 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 3-20 Total Generation Capacity by 2025-2035 (GW)

	No CPP	Base Case (CPP)	2% HRI at $50/kW	4.5% HRI at $50/kW	4.5% HRI at $100/kW
2025					
Coal	183	177	181	182	179
NG Combined Cycle (existing)	264	264	264	264	264
NG Combined Cycle (new)	1	2	2	2	2
Combustion Turbine	152	151	152	152	152
Oil/Gas Steam	78	79	79	79	80
Non-Hydro Renewables	203	206	205	204	206
Hydro	110	110	110	110	110
Nuclear	87	89	86	85	86
Other	8	8	8	8	8
Total	1,085	1,086	1,086	1,086	1,086
2030					
Coal	182	176	180	181	177
NG Combined Cycle (existing)	264	264	264	264	264
NG Combined Cycle (new)	9	12	9	9	9
Combustion Turbine	156	153	156	157	157
Oil/Gas Steam	78	79	79	79	80
Non-Hydro Renewables	255	260	255	254	255
Hydro	110	111	110	110	110
Nuclear	84	87	83	82	83
Other	8	8	8	8	8
Total	1,145	1,149	1,145	1,144	1,144
2035					
Coal	177	173	175	177	171
NG Combined Cycle (existing)	264	264	264	264	264
NG Combined Cycle (new)	35	39	35	33	35
Combustion Turbine	170	167	171	172	174
Oil/Gas Steam	78	79	79	79	80
Non-Hydro Renewables	257	263	258	257	257
Hydro	111	111	111	111	111
Nuclear	84	85	83	82	83
Other	8	8	8	8	8
Total	1,184	1,188	1,184	1,183	1,183

Table 3-21 Percent Change in Total Generation Capacity by 2025-2035, Relative to Base Case Scenario (CPP)

	No CPP	Base Case (CPP)	2% HRI at $50/kW	4.5% HRI at $50/kW	4.5% HRI at $100/kW
2025					
Coal	3.2%	--	2.1%	2.9%	0.7%
NG Combined Cycle (existing)	0.0%	--	0.0%	0.0%	0.0%
NG Combined Cycle (new)	-33.4%	--	-24.4%	-29.6%	-12.0%
Combustion Turbine	0.3%	--	0.3%	0.3%	0.4%
Oil/Gas Steam	-0.4%	--	0.2%	1.1%	2.2%
Non-Hydro Renewables	-1.4%	--	-0.6%	-0.8%	0.0%
Hydro	-0.3%	--	-0.3%	-0.3%	-0.3%
Nuclear	-2.9%	--	-3.2%	-4.9%	-3.8%
Other	0.0%	--	0.0%	0.0%	0.0%
Total	-0.1%	--	-0.1%	0.0%	0.0%
2030					
Coal	3.2%	--	2.1%	2.9%	0.8%
NG Combined Cycle (existing)	0.0%	--	0.0%	0.0%	0.0%
NG Combined Cycle (new)	-22.6%	--	-20.2%	-28.4%	-21.3%
Combustion Turbine	1.5%	--	2.1%	2.3%	2.6%
Oil/Gas Steam	-0.4%	--	0.2%	1.0%	2.1%
Non-Hydro Renewables	-2.0%	--	-2.0%	-2.2%	-2.0%
Hydro	-0.1%	--	-0.1%	-0.1%	-0.1%
Nuclear	-3.4%	--	-3.7%	-5.5%	-4.4%
Other	0.0%	--	0.0%	0.0%	0.0%
Total	-0.3%	--	-0.3%	-0.4%	-0.4%
2035					
Coal	2.7%	--	1.5%	2.6%	-0.9%
NG Combined Cycle (existing)	0.0%	--	0.0%	0.0%	0.0%
NG Combined Cycle (new)	-11.3%	--	-10.3%	-14.7%	-10.9%
Combustion Turbine	2.3%	--	3.0%	3.3%	4.7%
Oil/Gas Steam	-0.4%	--	0.2%	1.0%	2.1%
Non-Hydro Renewables	-2.1%	--	-2.1%	-2.4%	-2.2%
Hydro	0.0%	--	0.0%	0.0%	0.0%
Nuclear	-2.0%	--	-2.4%	-4.1%	-3.0%
Other	0.0%	--	0.0%	0.0%	0.0%
Total	-0.3%	--	-0.3%	-0.4%	-0.4%

Table 3-22 Percent Change in Total Generation Capacity by 2025-2035, Relative to No CPP Scenario

	No CPP	Base Case (CPP)	2% HRI at $50/kW	4.5% HRI at $50/kW	4.5% HRI at $100/kW
2025					
Coal	--	-3.1%	-1.1%	-0.3%	-2.4%
NG Combined Cycle (existing)	--	0.0%	0.0%	0.0%	0.0%
NG Combined Cycle (new)	--	50.1%	13.5%	5.6%	32.1%
Combustion Turbine	--	-0.3%	0.0%	0.0%	0.0%
Oil/Gas Steam	--	0.4%	0.7%	1.5%	2.6%
Non-Hydro Renewables	--	1.5%	0.8%	0.7%	1.4%
Hydro	--	0.3%	0.0%	0.0%	0.0%
Nuclear	--	3.0%	-0.3%	-2.0%	-0.9%
Other	--	0.0%	0.0%	0.0%	0.0%
Total	--	0.1%	0.0%	0.0%	0.0%
2030					
Coal	--	-3.1%	-1.0%	-0.3%	-2.3%
NG Combined Cycle (existing)	--	0.0%	0.0%	0.0%	0.0%
NG Combined Cycle (new)	--	29.3%	3.1%	-7.4%	1.7%
Combustion Turbine	--	-1.5%	0.5%	0.7%	1.1%
Oil/Gas Steam	--	0.4%	0.6%	1.5%	2.5%
Non-Hydro Renewables	--	2.1%	0.1%	-0.2%	0.0%
Hydro	--	0.1%	0.0%	0.0%	0.0%
Nuclear	--	3.6%	-0.3%	-2.1%	-0.9%
Other	--	0.0%	0.0%	0.0%	0.0%
Total	--	0.3%	0.0%	-0.1%	-0.1%
2035					
Coal	--	-2.7%	-1.2%	-0.2%	-3.5%
NG Combined Cycle (existing)	--	0.0%	0.0%	0.0%	0.0%
NG Combined Cycle (new)	--	12.7%	1.1%	-3.8%	0.4%
Combustion Turbine	--	-2.3%	0.6%	1.0%	2.3%
Oil/Gas Steam	--	0.4%	0.6%	1.5%	2.5%
Non-Hydro Renewables	--	2.2%	0.0%	-0.3%	-0.1%
Hydro	--	0.0%	0.0%	0.0%	0.0%
Nuclear	--	2.1%	-0.3%	-2.1%	-1.0%
Other	--	0.0%	0.0%	0.0%	0.0%
Total	--	0.3%	0.0%	-0.1%	-0.1%

Table 3-23 Projected Natural Gas Combined Cycle Capacity Additions and Changes Relative to Base Case (CPP)

	Cumulative Capacity Additions: NGCC (GW)			Incremental Cumulative Capacity Additions, Relative to the Base Case (CPP)			Percent Change in Incremental Cumulative Capacity Additions, Relative to the Base Case (CPP)		
	2025	2030	2035	2025	2030	2035	2025	2030	2035
No CPP	1.4	9.2	34.5	-0.7	-2.7	-4.4	-33.4%	-22.6%	-11.3%
Base Case (CPP)	2.2	11.9	38.9	--	--	--	--	--	--
2% HRI at $50/kW	1.6	9.5	34.9	-0.5	-2.4	-4.0	-24.4%	-20.2%	-10.3%
4.5% HRI at $50/kW	1.5	8.5	33.2	-0.6	-3.4	-5.7	-29.6%	-28.4%	-14.7%
4.5% HRI at $100/kW	1.9	9.4	34.7	-0.3	-2.5	-4.2	-12.0%	-21.3%	-10.9%

Table 3-24 Projected Renewable Capacity Additions and Changes Relative to Base Case (CPP)

	Cumulative Capacity Additions: Renewables (GW)			Incremental Cumulative Capacity Additions, Relative to the Base Case (CPP)			Percent Change in Incremental Cumulative Capacity Additions, Relative to the Base Case (CPP)		
	2025	2030	2035	2025	2030	2035	2025	2030	2035
No CPP	89.5	142.2	145.4	-3.3	-5.5	-5.6	-3.6%	-3.7%	-3.7%
Base Case (CPP)	92.8	147.7	151.0	--	--	--	--	--	--
2% HRI at $50/kW	91.2	142.4	145.4	-1.7	-5.3	-5.6	-1.8%	-3.6%	-3.7%
4.5% HRI at $50/kW	90.9	141.7	144.7	-1.9	-6.0	-6.3	-2.1%	-4.0%	-4.2%
4.5% HRI at $100/kW	92.5	142.3	145.1	-0.4	-5.4	-5.8	-0.4%	-3.6%	-3.9%

Table 3-25 Projected Natural Gas Combined Cycle Capacity Additions and Changes Relative to No CPP Scenario

	Cumulative Capacity Additions: NGCC (GW)			Incremental Cumulative Capacity Additions, Relative to No CPP Scenario			Percent Change in Incremental Cumulative Capacity Additions, Relative to No CPP Scenario		
	2025	2030	2035	2025	2030	2035	2025	2030	2035
No CPP	1.4	9.2	34.5	--	--	--	--	--	--
Base Case (CPP)	2.2	11.9	38.9	0.7	2.7	4.4	50.1%	29.3%	12.7%
2% HRI at $50/kW	1.6	9.5	34.9	0.2	0.3	0.4	13.5%	3.1%	1.1%
4.5% HRI at $50/kW	1.5	8.5	33.2	0.1	-0.7	-1.3	5.6%	-7.4%	-3.8%
4.5% HRI at $100/kW	1.9	9.4	34.7	0.5	0.2	0.1	32.1%	1.7%	0.4%

Table 3-26 Projected Renewable Capacity Additions and Changes Relative to No CPP Scenario

	Cumulative Capacity Additions: Renewables (GW)			Incremental Cumulative Capacity Additions, Relative to No CPP Scenario			Percent Chane in Incremental Cumulative Capacity Additions, Relative to No CPP Scenario		
	2025	2030	2035	2025	2030	2035	2025	2030	2035
No CPP	89.5	142.2	145.4	--	--	--	--	--	--
Base Case (CPP)	92.8	147.7	151.0	3.3	5.5	5.6	3.7%	3.8%	3.9%
2% HRI at $50/kW	91.2	142.4	145.4	1.6	0.2	0.0	1.8%	0.1%	0.0%
4.5% HRI at $50/kW	90.9	141.7	144.7	1.4	-0.5	-0.7	1.5%	-0.4%	-0.5%
4.5% HRI at $100/kW	92.5	142.3	145.1	2.9	0.1	-0.2	3.3%	0.1%	-0.2%

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

Relative to the base case (CPP), EPA projects a 7 to 9 percent increase in overall coal production for use by the electric power sector in the illustrative policy scenarios in 2030. Most of this increase is projected to occur in production of western subbituminous coals. Relative to the No CPP scenario, under the illustrative policy scenarios coal use is projected to decrease, with most of the reduction in 2030 and 2035 occurring in the west, followed by production in Appalachia.

Table 3-27 2025 Projected Coal Production for the Electric Power Sector (million short tons)

	No CPP	Base Case (CPP)	2% HRI at $50/kW	4.5% HRI at $50/kW	4.5% HRI at $100/kW
Appalachia	74	70	75	73	73
Interior	126	123	124	123	122
West	323	300	322	325	320
Waste Coal	2	2	2	2	2
Total	525	495	522	524	517

Table 3-28 2030 Projected Coal Production for the Electric Power Sector (million short tons)

	No CPP	Base Case (CPP)	2% HRI at $50/kW	4.5% HRI at $50/kW	4.5% HRI at $100/kW
Appalachia	62	58	61	61	60
Interior	124	123	124	124	124
West	324	287	320	322	316
Waste Coal	2	2	2	2	2
Total	513	470	507	510	503

Table 3-29 2035 Projected Coal Production for the Electric Power Sector (million short tons)

	No CPP	Base Case (CPP)	2% HRI at $50/kW	4.5% HRI at $50/kW	4.5% HRI at $100/kW
Appalachia	43	47	43	41	41
Interior	114	112	113	117	115
West	306	264	302	304	298
Waste Coal	2	2	2	2	2
Total	465	424	460	465	456

Relative to the base case (CPP) EPA projects a 1 to 3 percent reduction in total gas use in the electric power sector, depending on the illustrative compliance scenario and year.

Table 3-30 Projected Power Sector Gas Use

	Power Sector Gas Use (TCF)			Percent Change in Power Sector Gas Use, Relative to Base Case (CPP)			Percent Change in Power Sector Gas Use, Relative to No CPP		
	2025	2030	2035	2025	2030	2035	2025	2030	2035
No CPP	11.96	12.18	13.65	-1.5%	-1.5%	-0.9%	--	--	--
Base Case (CPP)	12.14	12.36	13.78	--	--	--	1.5%	1.5%	0.9%
2% HRI at $50/kW	11.84	12.15	13.62	-2.5%	-1.7%	-1.1%	-1.0%	-0.3%	-0.2%
4.5% HRI at $50/kW	11.72	12.05	13.52	-3.4%	-2.5%	-1.9%	-1.9%	-1.0%	-1.0%
4.5% HRI at $100/kW	11.73	12.08	13.56	-3.4%	-2.3%	-1.6%	-1.9%	-0.8%	-0.7%

3.7.7 Projected Fuel Price, Market, and Infrastructure Impacts

Relative to the base case (CPP), the illustrative policy scenarios result in small changes in electric power sector delivered coal and natural gas prices, on a Btu-weighted average basis. Depending on the illustrative policy scenario and year, the model projects changes to delivered coal prices that range from a small increase to a small decrease, less than one percent. Additionally, depending on the illustrative policy scenario and year, EPA projects a reduction in delivered natural gas prices on the order of about 1 percent.

Table 3-31 Projected Average Minemouth and Delivered Coal Prices (2016$/MMBtu)

	Minemouth			Delivered - Electric Power Sector		
	2025	2030	2035	2025	2030	2035
No CPP	1.29	1.35	1.42	2.03	2.09	2.15
Base Case (CPP)	1.29	1.36	1.45	2.03	2.09	2.15
2% HRI at $50/kW	1.29	1.35	1.42	2.03	2.09	2.14
4.5% HRI at $50/kW	1.29	1.35	1.42	2.04	2.11	2.16
4.5% HRI at $100/kW	1.29	1.35	1.42	2.04	2.10	2.15

Table 3-32 Projected Average Henry Hub (spot) and Delivered Natural Gas Prices (2016$/MMBtu)

	Henry Hub			Delivered - Electric Power Sector		
	2025	2030	2035	2025	2030	2035
No CPP	3.56	3.67	3.74	3.58	3.64	3.56
Base Case (CPP)	3.61	3.70	3.75	3.62	3.65	3.56
2% HRI at $50/kW	3.56	3.65	3.73	3.58	3.62	3.54
4.5% HRI at $50/kW	3.54	3.64	3.71	3.57	3.61	3.53
4.5% HRI at $100/kW	3.55	3.64	3.71	3.57	3.61	3.53

Table 3-33 Percent Change in Projected Average Henry Hub (spot) and Delivered Natural Gas Prices, Relative to Base Case (CPP)

	Henry Hub			Delivered - Electric Power Sector		
	2025	2030	2035	2025	2030	2035
No CPP	-1.4%	-0.8%	-0.2%	-1.1%	-0.3%	0.1%
Base Case (CPP)	--	--	--	--	--	--
2% HRI at $50/kW	-1.4%	-1.3%	-0.6%	-1.1%	-0.9%	-0.4%
4.5% HRI at $50/kW	-1.7%	-1.6%	-1.0%	-1.4%	-1.1%	-0.7%
4.5% HRI at $100/kW	-1.6%	-1.6%	-1.0%	-1.3%	-1.1%	-0.7%

Table 3-34 Percent Change in Projected Average Henry Hub (spot) and Delivered Natural Gas Prices, Relative to No CPP Scenario

	Henry Hub			Delivered - Electric Power Sector		
	2025	2030	2035	2025	2030	2035
No CPP	--	--	--	--	--	--
Base Case (CPP)	1.4%	0.8%	0.2%	1.2%	0.3%	-0.1%
2% HRI at $50/kW	0.0%	-0.5%	-0.4%	0.1%	-0.5%	-0.4%
4.5% HRI at $50/kW	-0.4%	-0.8%	-0.8%	-0.3%	-0.8%	-0.8%
4.5% HRI at $100/kW	-0.2%	-0.8%	-0.8%	-0.1%	-0.8%	-0.8%

3.7.8 Projected Retail Electricity Prices

Relative to the base case (which includes CPP), EPA estimates the impact of the illustrative policy scenarios on retail electricity prices to be very small, on average.[19] See Table 3-35.[20] Given the limitations of this analysis, including the uncertainty regarding state implementation (see section 3.9), the RIA presents retail price projections at a national level. Under the illustrative policy scenarios, EPA projects changes in average retail electricity prices across the contiguous U.S. ranging from a one half of one percent decrease to no change, relative to the base case (CPP). See Table 3-36. Relative to the repeal scenario, EPA projects national changes in average retail electricity prices to be similarly small, ranging from a one half of one percent increase to a one tenth of one percent decrease. See Table 3-37.

Table 3-35 Projected Contiguous U.S. Retail Electricity Prices (cents/kWh), 2025-2035

	2025	2030	2035
No CPP	10.1	10.2	10.3
Base Case (CPP)	10.2	10.3	10.3
2% HRI at $50/kW	10.1	10.3	10.3
4.5% HRI at $50/kW	10.1	10.2	10.2
4.5% HRI at $100/kW	10.1	10.3	10.3

[19] 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

[20] The base case electricity prices assume that no allowance value from the CPP is used to lower electricity prices. If allowance value was used to reduce electricity prices, the difference in electricity prices from the base case reported in Table 3-29 would be smaller.

Table 3-36 Percent Change in Projected Contiguous U.S. Retail Electricity Prices, Relative to Base Case (CPP), 2025-2035

	2025	2030	2035
No CPP	-0.5%	-0.4%	-0.1%
2% HRI at $50/kW	-0.3%	-0.2%	-0.1%
4.5% HRI at $50/kW	-0.5%	-0.4%	-0.2%
4.5% HRI at $100/kW	-0.2%	0.0%	0.0%

Table 3-37 Percent Change in Projected Contiguous U.S. Retail Electricity Prices, Relative to No CPP Scenario, 2025-2035

	2025	2030	2035
Base Case (CPP)	0.5%	0.4%	0.1%
2% HRI at $50/kW	0.2%	0.2%	0.0%
4.5% HRI at $50/kW	0.0%	0.0%	-0.1%
4.5% HRI at $100/kW	0.3%	0.4%	0.1%

3.8 Demand-side Energy Efficiency Sensitivity to the Base Case (CPP)

An additional scenario was conducted that included CPP with a revised electric demand projection reflecting demand-side energy efficiency measures that were allowed as a compliance option under CPP. This scenario is provided as a sensitivity analysis to the base case for this RIA, and shows the potential effects of CPP with and without demand-side energy efficiency, and in relation to a Repeal Scenario. These scenarios are compared to each other to provide information on CPP, alternative electric demand considering demand-side EE with CPP, and repeal of CPP.

3.8.1 Demand-side Energy Efficiency Revised Electric Demand Projection

For this EE illustrative scenario, the level of reduced electricity consumption (i.e., electricity savings) due to the adoption of demand-side energy efficiency for compliance with the CPP is derived from the AEO 2017 reference case and "no CPP" side case (EIA, 2017), which were from the most recent version of the AEO available when the modeling for this proposal RIA was commenced. The difference between projected electricity demand in the two cases is used as an estimate of reduced electricity demand due to demand-side energy efficiency used for compliance with the CPP in the alternative base case. Regional demand reductions from the

AEO 2017 analysis are applied to each region in the IPM model. The national savings are summarized in Table 3-38. In 2025, 2030, and 2035, these savings represent 2.6 percent, 4.0 percent, and 4.2 percent of electricity sales to end users, respectively. Note that these levels are lower than (approximately half of) the levels assumed for CPP compliance in the illustrative mass-based and rate-based scenarios in the 2015 CPP RIA (U.S. EPA, 2015a).

Table 3-38 Change in Electricity Demand Due to Demand-side Energy Efficiency, CPP Scenario vs. No CPP Scenario in AEO2017

	2025	2030	2035
Change in Electricity Demand (TWh)	101	159	171
Percent Change in Electricity Demand	2.6%	4.0%	4.2%

3.8.2 Demand-side Energy Efficiency Costs

To estimate the cost of achieving these electricity savings, the cost to save a MWh (2016$/MWh) were multiplied by the electricity savings in each year. These levelized costs are referred to as "levelized costs of saved energy" (LCSE). The LCSE value used is taken from an extensive database of utility energy efficiency program costs and savings as publicly reported to their state utility commissions and compiled and analyzed by Lawrence Berkeley National Laboratory (LBNL) (Hoffman et al., 2017). The database represents more than 70 percent of total utility program savings from the years 2009 through 2011 and was collected from more than 100 energy efficiency program administrators across more than 30 states. Data were collected from over 1,700 individual programs covering more than 4,000 individual program-years of data points. This LCSE value is $46/MWh (2012$). The value is the cost per gross MWh saved and is calculated using a discount rate of 6 percent. This value represents the total costs including both the costs to the program administrator and the participants in the program. To account for free ridership, spillover, etc., this value is grossed up by a net-to-gross (NTG) factor of 0.85.[21] This NTG value is based upon an EPA compilation and analysis of NTG factors used by utilities across the country (Synapse, 2015). The resulting value is then inflated to 2016$ and the result is $57.3 2016$/MWh (the levelized cost per net MWh saved) in each year of the

[21] See Synapse, 2015, for a detailed discussion of NTG definitions and how factors are derived.

analysis and is applied nationally.[22] See Table 3-39 for a summary of total demand side-energy efficiency (DS-EE) costs by year.

The LCSE value used in this analysis differs from the one used in the RIA for the final CPP in 2015 (U.S. EPA, 2015a). In that analysis, at lower levels of savings from energy efficiency, costs were assumed to be double the value found in the literature and then to decline by 20 percent and then 40 percent as higher levels of savings were achieved. This approach was based on the assumption that LCSE starts much higher than the average costs and declines as savings increase, due to factors such as economies of scale. This resulted in significantly conservative (higher values for LCSE by year and level of savings. As noted in the Demand-side Energy Efficiency TSD for the 2015 RIA (U.S. EPA, 2015b), the literature is inconclusive on whether costs increase or decrease at higher levels of savings, with preliminary analyses falling on both sides of the issue. An analysis by LBNL based on the same data set as used for their 2015 cost of saved energy analysis (cited above) shows increasing costs at higher levels of savings LBNL (Hoffman et al., 2015). The current analysis assumes neither increasing or decreasing costs but rather a level LCSE value, in constant dollars, across all years of the analysis and regardless of the level of savings.

Table 3-39 Costs of Demand-side Energy Efficiency (billions of 2016$)

	2025	2030	2035
Demand-Side EE Costs (2016$)	$5.8	$9.1	$9.8

3.8.3 Demand-side Energy Efficiency Sensitivity to the Base Case: Projected EE Benefits and Compliance Costs

The compliance costs of a repeal scenario relative to a base case (CPP) with EE are estimated in Table 3-40 below, in a manner consistent with the accounting conventions specified by the OMB Guidance for Implementing E.O. 13771.[23] This OMB guidance states that

[22] The calculation is (($46 2012$/MWh gross) / (0.85 net MWh/gross MWh)) x (1.059 2016$/2012$) = $57.3 2016$/net MWh.

[23] U.S. Office of Management and Budget. 2017. "Guidance Implementing Executive Order 13771, Titled 'Reducing Regulation and Controlling Regulatory Costs'" [Memorandum]. Available at: < https://www.whitehouse.gov/sites/whitehouse.gov/files/omb/memoranda/2017/M-17-21-OMB.pdf> Accessed July 19, 2018.

accounting for "savings, such as fuel savings associated with energy efficiency investments, as benefits is a common accounting convention followed in the OMB Office of Information and Regulatory Affairs' reports to Congress on the benefits and costs of Federal regulations."

Under the accounting convention consistent with OMB guidance related to EO 13771, EPA projects that the gross compliance costs of the repeal relative to the base case (CPP) with energy efficiency, excluding the forgone energy cost savings attributable to EE, range from -$6.5 billion in 2025 to -$10.2 billion in 2035 (Table 3-40). These projected compliance costs do not include the forgone benefit of energy cost savings,[24] which range from $5.6 billion in 2025 to $10.5 billion in 2035 (Table 3-40). These excluded energy cost savings reflect both forgone variable cost savings (e.g., fuel and variable O&M) as well as forgone fixed cost savings (e.g., new power plants, and fixed O&M).

[24] For the purposes of this document, "energy cost savings" is the value of the reduced costs of producing electricity that is attributable to the demand-side energy efficiency programs. We estimate this value by calculating the difference in projected system costs between the two CPP modeling scenarios, with and without EE. The term "energy savings" is also commonly used to describe the amount of energy saved as a result of demand-side energy efficiency measures, usually expressed in terms of megawatt-hours, but in this document, it will refer to the financial value of those savings unless otherwise noted.

Table 3-40 Annualized Compliance Costs of the No CPP Scenario (billions of 2016$)

		2025	2030	2035
Total Power Sector Generating Costs				
	Repeal Scenario (A)	144.5	156.1	165.2
	CPP without EE (B)	145.3	156.8	165.6
	CPP with EE (C)	139.7	147.4	155.1
Demand-Side EE Costs				
	CPP without EE	0.0	0.0	0.0
	CPP with EE (D)	5.8	9.1	9.8
Compliance Costs of CPP Repeal that Include the Benefit of Forgone Energy Cost Savings for CPP with EE				
	CPP without EE (A-B)	-0.7	-0.7	-0.4
	CPP with EE (E = A-C-D)	-0.9	-0.5	0.3
Forgone Benefit of Energy Cost Savings (Not Included in Compliance Cost of CPP Repeal)				
	CPP without EE	0.0	0.0	0.0
	CPP with EE (F = B-C)	5.6	9.4	10.5
Compliance Costs of CPP Repeal (Consistent with OMB EO 13771)				
	CPP without EE (A-B)	-0.7	-0.7	-0.4
	CPP with EE (E-F)*	-6.5	-9.8	-10.2

Note: Includes MR&R costs (see 3.6)
* The full equation is (A-C-D) - (B-C), which simplifies to A-B-D.

Note that estimates of the forgone benefit of energy cost savings presented in Table 3-40 cannot be added to the forgone monetized benefits presented in Chapter 4 of this RIA. The benefit estimates presented in the main analysis of the RIA are based upon a base case with CPP without demand-side energy efficiency. The trajectory of the emissions changes estimated in the main analysis for this proposed action are different than they would be assuming demand-side energy efficiency was used as CPP compliance strategy. Also, for this reason, the cost of the repeal estimated using this different base case should not be compared to, or otherwise presented alongside, the forgone environmental benefits reported elsewhere in this RIA.

3.8.4 Demand-side Energy Efficiency Sensitivity to the Base Case: Projected Emissions

Under the base case (CPP) with energy efficiency, EPA projects a 6 percent reduction in CO_2 emissions in 2025, a 7 percent reduction in CO_2 emissions in 2030, and a 6 percent reduction in CO_2 emissions in 2035, relative to the illustrative repeal scenario. Additionally, relative to a repeal scenario, EPA projects that the base case (CPP) with energy efficiency would result in reductions of SO_2 (about 8 percent annually across 2025-2035), reductions in NO_X (about 7 percent annually across 2025-2035), and reduction in mercury (about 7-8 percent annually over 2025-2035). See the following tables. These emissions impacts have not been quantified in Chapter 4 for the CPP with EE scenario and thus net benefits for this scenario are not presented in Chapter 6.

Table 3-41 Projected CO_2 Emission Impacts, Relative to Illustrative No CPP Scenario

	CO_2 Emissions (MM Short Tons)			CO_2 Emissions Change (MM Short Tons)			CO_2 Emissions Percent Change Relative to Illustrative Repeal Scenario		
	2025	2030	2035	2025	2030	2035	2025	2030	2035
Repeal Scenario	1,829	1,811	1,794	--	--	--	--	--	--
Base Case (CPP)	1,780	1,737	1,728	-50	-74	-66	-3%	-4%	-4%
Base Case (CPP) with EE	1,725	1,695	1,682	-104	-117	-112	-6%	-7%	-6%

Table 3-42 Projected SO_2, NO_X, and Mercury Emissions

	SO_2 (thousand tons)	NO_X (thousand tons)	Mercury (tons)
2025			
No CPP	959	874	4.9
Base Case (CPP)	923	842	4.7
Base Case (CPP) with EE	883	814	4.5
2030			
No CPP	950	833	4.7
Base Case (CPP)	891	786	4.4
Base Case (CPP) with EE	871	772	4.3
2035			
No CPP	865	783	4.3
Base Case (CPP)	821	740	4.1
Base Case (CPP) with EE	799	731	4.0

Table 3-43 Projected SO_2, NO_X, and Mercury Emission Impacts, Relative to Illustrative No CPP Scenario

	SO_2 (thousand tons)	NO_X (thousand tons)	Mercury (tons)
2025			
No CPP	--	--	--
Base Case (CPP)	-3.7%	-3.7%	-3.5%
Base Case (CPP) with EE	-7.9%	-6.8%	-7.2%
2030			
No CPP	--	--	--
Base Case (CPP)	-6.3%	-5.7%	-5.1%
Base Case (CPP) with EE	-8.3%	-7.3%	-7.6%
2035			
No CPP	--	--	--
Base Case (CPP)	-5.1%	-5.5%	-4.2%
Base Case (CPP) with EE	-7.6%	-6.6%	-6.9%

3.9 Limitations of Analysis

Cost estimates for the proposal scenarios 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; to the extent that utilities and/or energy regulators have different judgments about future conditions affecting the economics of operation or pollution control, proposed 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. Regarding fuel supply, EPA observes that future long-term natural gas price projections used in this analysis are somewhat higher than current observed short-term market rates (e.g., Henry Hub prices). EPA is exploring doing additional work regarding these data, and is soliciting comment on alternative data, assumptions, and sensitivity analyses that EPA might consider for the final rule analysis.

As previously stated, this analysis is intended to be illustrative, and not intended to evaluate the many specific approaches that individual states might choose as they implement BSER, or how sources might have responded to those specific policy signals or requirements. It is important to note, that EPA has not analyzed or modeled a specific standard of performance, given that this proposal establishes BSER, and it is up to states to determine appropriate standards of performance for sources. It is important to note that 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.

EPA assumed different heat rate assumptions in the base case for this RIA than the illustrative policy scenarios. In the base case (CPP), EPA assumed that HRI was available at assumptions consistent with the final CPP ($100/kW) and about 2 to 4 percent improvement depending on the region, consistent with how HRI was modeled in the final CPP), and in this scenario EPA modeling estimates an installation of less than 5 GW of capacity. The No CPP scenario does not allow any heat rate improvement.

The base case assumes the states adopt a specific approach for implementing the CPP. States have flexibility under the CPP to comply using other approaches, including using a rate-based approach, allowing for interstate trading, and participating in the Clean Energy Incentive Program (CEIP). States adopting mass-based plans must address leakage, which is not modeled in the illustrative CPP approach in this RIA. Changes in the assumed state plan approach for CPP compliance or compliance methods may affect the estimated benefits and costs.

The analysis in this chapter is limited to the effects of the proposed regulation 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 proposed rule (as well as the benefits from changes in emissions from and in those areas).[25]

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 is small.

Potential changes in emissions other than emissions of CO_2, SO_2, NO_X and Hg from the electricity sector are not estimated directly using IPM and are not reported in this chapter. This includes hazardous air pollutants and direct particulate matter ($PM_{2.5}$) emissions and water emissions. 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

[25] The limited exception to this is MR&R costs, as MR&R costs are estimated for 49 states, including Alaska and Hawaii. One contiguous state is estimated to have no MR&R costs, as it is expected to submit a negative declaration.

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 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.[26] 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.

The demand-side energy efficiency sensitivity analysis is an illustrative scenario that provides information on the potential effects had demand-side energy efficiency been used for compliance with the CPP. As described in section 3.8, the level of reduced electricity consumption through energy efficiency are derived from the AEO 2017 reference and "no CPP" side case and is therefore subject to all the assumptions that underlie those scenarios. These are summarized at length in U.S. EIA, 2017.

In addition to the level of reduced electricity consumption, the assumed cost of saved energy, as discussed in section 3.8.2, is another key component of the demand-side EE sensitivity analysis. The values used in this analysis are based on a review of energy efficiency

[26] 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.

data and studies, and expert judgment. As noted, the levelized cost saved energy used in our analysis is \$57.3 2016\$/MWh. This LCSE value is the total levelized cost, including both program and participant costs. Analysis of energy efficiency costs is limited and the results vary significantly. Studies are of two types: bottom-up engineering-based analyses and top-down analyses employing econometric techniques. Bottom-up engineering-based analyses are much more prevalent. They are carried out by third-party evaluators and reviewed in regulatory proceedings by oversight entities such as state utility commissions that serve to protect the interests of utility customers while allowing a fair return to utility investors. The value chosen for the current analysis is based upon the most extensive national database of bottom-up, engineering-based analyses of energy efficiency costs. The value falls within, but at the lower end, of the range of results from top-down econometric analyses. See U.S. EPA, 2015a and 2017, for more extensive discussions of the limitations of the analysis of energy efficiency costs.

Demand-side energy-efficiency in response to the CPP is applied in every state in the Base Case (CPP) with EE scenario. However, as observed in the Base Case (CPP), the total emissions from affected sources is projected to be less than the mass-based goals for existing sources, suggesting that many states do not need to undertake compliance activities under the CPP, including demand-side EE. Changing the analysis so that demand-side energy efficiency is only applied in those states where it could be utilized for compliance would affect the projected emissions changes and costs between the alternative base case and the policy scenarios.

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

4.1 Introduction

As compared to the standards of performance that it replaces (i.e., the 2015 Clean Power Plan) and as documented in Chapter 3, implementing the proposed rule is expected to increase emissions of carbon dioxide (CO_2) and increase the level of emissions of certain pollutants in the atmosphere that adversely affect human health. These emissions include directly emitted fine particles sized 2.5 microns and smaller ($PM_{2.5}$), sulfur dioxide (SO_2), nitrogen dioxide (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 forgone domestic climate benefits associated with the increase in CO_2 emissions and forgone domestic health benefits associated with the increase in $PM_{2.5}$ and ground-level ozone. We refer to the health benefits as "co-benefits" (or, "ancillary co-benefits") in this RIA because they occur as a result of implementing the policy but are not necessarily the intended outcome of the standards of performance. By contrast, reducing CO_2 is a goal of this policy, and so we treat CO_2 as the "targeted pollutant". Data, resource, and methodological limitations prevent EPA from estimating all forgone domestic climate benefits and forgone 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.

Elsewhere in the RIA, including the Executive Summary, estimates of forgone benefits are presented as negative benefit values to make it easier for readers to compare costs and benefits. In this chapter, which only presents estimated forgone benefits, these figures are not presented as negative values, but are shown as positive values.

4.2 Climate Change Impacts

In 2009, 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 EPA regulation of GHGs from EGU sources. Since 2009, other science assessments suggest accelerating trends[2].

4.3 Approach to Estimating Forgone Climate Benefits from CO_2

We estimate the forgone climate benefits from this proposed 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

[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. 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.

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 "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. 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.

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).[3] 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 the recent recommendations from the National Academies of Sciences, Engineering, and Medicine to further update to 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 the model runs for each discount rate for the years 2015 to 2050. 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

[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

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.

Table 4-1 Interim Domestic Social Cost of CO2, 2015-2050 (in 2016$ per metric ton)*

	Discount Rate and Statistic	
Year	**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

* These SC-CO_2 values are stated in $/metric ton CO_2 and rounded the nearest dollar. These values may be converted to $/short ton using the conversion factor 0.90718474 metric tons in a 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 forgone domestic climate benefits in the three analysis years (2025, 2030, 2035) for the four illustrative scenarios, compared to the base case.

Table 4-2 Estimated Forgone Domestic Climate Benefits, Relative to Base Case (CPP) (billions 2016$)*

	3% Discount Rate	7% Discount Rate
No CPP		
2025	0.32	0.053
2030	0.53	0.092
2035	0.51	0.10
2% HRI at $50/kW		
2025	0.24	0.039
2030	0.43	0.075
2035	0.43	0.080
4.5% HRI at $50/kW		
2025	0.21	0.034
2030	0.43	0.074
2035	0.46	0.086
4.5% HRI at $100/kW		
2025	0.13	0.021
2030	0.34	0.059
2035	0.34	0.064

* 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 does not reflect all of the recent recommendations of the National Academy's 2017 report or the most recent research, and the limited amount of research linking climate impacts to economic damages makes the 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 social cost of carbon, 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.

The National Academies' 2017 report also discussed the challenges in developing domestic SC-CO_2 estimates, noting that current integrated assessment models (IAMs) 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, 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 forgone global climate benefits from this proposed rulemaking using global SC-CO_2 estimates based on both 3 and 7 percent discount rates. Note EPA did not quantitatively project the full impact of the CPP on international trade and the location of production, so it is not possible to present analogous estimates of international costs resulting from the proposed 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 avoided compliance costs.

4.4 Approach to Estimating Forgone Human Health Ancillary Co-Benefits

As noted above, this proposed 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 forming ambient ground-level ozone. The EGU emissions associated with the base case and each of the four illustrative scenarios are shown in Table 4-3. The change in emissions between the base case and each illustrative scenario will in turn alter the ambient levels, population exposure and human health impacts associated with $PM_{2.5}$ and ozone. Finally, ambient levels 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 $PM_{2.5}$*

	SO_2 (thousand tons)	NO_X (thousand tons)	$PM_{2.5}$ (thousand tons)
2025			
No CPP	959	874	111
Base Case (CPP)	923	842	109
2% HRI at $50/kW	959	866	110
4.5% HRI at $50/kW	963	863	109
4.5% HRI at $100/kW	956	856	109
2030			
No CPP	950	833	112
Base Case (CPP)	891	786	110
2% HRI at $50/kW	943	825	111
4.5% HRI at $50/kW	943	825	111
4.5% HRI at $100/kW	935	818	110
2035			
No CPP	865	783	114
Base Case (CPP)	821	740	113
2% HRI at $50/kW	855	778	113
4.5% HRI at $50/kW	864	782	113
4.5% HRI at $100/kW	849	772	113

* 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.

This section is a summary of our approach to estimating the incidence and economic value of the forgone $PM_{2.5}$ and ozone-related ancillary co-benefits estimated for this proposed rule relative to a baseline that includes the 2015 CPP RIA. 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 BenMAP-CE user manual (U.S. EPA 2018a) provides 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 forgone ancillary health co-benefits do not account for the influence of future changes in the climate on ambient levels 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 $PM_{2.5}$ levels 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 proposed guidelines will affect the level and 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 foregone $PM_{2.5}$- 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.

Some portion of the foregone air quality and health benefits estimated for this rule will occur in areas not attaining the $PM_{2.5}$ or Ozone NAAQS. This RIA predicts increased levels of $PM_{2.5}$ and ozone in some locations compared to the base case that includes the 2015 CPP. In these instances, States would identify additional opportunities to reduce emissions from local sources relative to the base case. States may meet the NAAQS using other approaches, thus negating the increased $PM_{2.5}$ and ozone concentrations we predicted in this RIA. In this case, the forgone benefits would be lower than we estimated here and States would incur the costs of these alternative approaches. We did not separately estimate these costs and did not separately report the change in $PM_{2.5}$ or ozone in areas projected to not attain either standard. The base case, which includes the CPP, projected reduced EGU emissions in areas already attaining the NAAQS. And, in some cases, the CPP would have created “room” for new and expanding sources in these areas to increase pollutant emissions. In these instances, the forgone health co-benefits we estimated could be overestimated. The extent to which we over-estimated foregone health co-benefits will depend on how States and the U.S. EPA choose to implement the NAAQS and address Prevention of Significant Deterioration (PSD) requirements. Conversely, the policy cases may inhibit the ability of sources to expand, yielding foregone benefits.

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 forgone benefits from this proposed rule. Spatial fields of air quality were prepared 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 for scenarios that reflect EGU emissions analyzed in this proposed rule RIA. The EGU emissions for each of the scenarios 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)[4] (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.

Several types of photochemical model runs were performed as part of this analysis. The modeling included annual model runs 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 proposed 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 emissions in 2025, 2030,

[4] CAMx version 6.40 was used for the modeling to support the proposal RIA. This version of CAMx is the latest public release version of the model at the time of proposal.

and 2035 for the base case which includes the 2015 CPP final rule and each of the four illustrative scenarios we analyzed for this proposal. Due to timing constraints we did not perform explicit air quality modeling for each of the 2025/2030/2035 base case and the illustrative scenarios. Rather, we used emissions data and the results of the 2011 and 2023 modeling in conjunction with source apportionment modeling for 2023 to estimate the ozone and $PM_{2.5}$ concentrations for each year of the base case which includes the 2015 CPP final rule and the illustrative scenarios. 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 in the model to obtain hourly gridded[5] contributions from the emissions in each individual tag to hourly modeled concentrations of ozone and $PM_{2.5}$.[6] For this analysis we performed source apportionment modeling for ozone and $PM_{2.5}$ based on 2023 emissions using the tools in CAMx[7] to obtain the contributions from EGU emissions as well as other sources to ozone and to $PM_{2.5}$ component species concentrations.[8]

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 NO_X and VOC emissions 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. For $PM_{2.5}$, 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-

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

[6] 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.

[7] 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.

[8] 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.

fired units or non-coal units.[9] In addition to tagging 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 those EGUs that were operating in the 2023 case, but are now expected to retire before 2030[10]; 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;[11]
- 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 $PM_{2.5}$ for the base case and illustrative scenarios case in 2025, 2030, and 2035. The following data were used to create the spatial fields of ozone and $PM_{2.5}$ for the base case and the four illustrative scenarios case in 2025, 2030, and 2035:

(1) 2023 annual EGU SO_2, NO_X, and directly emitted $PM_{2.5}$ emissions and 2023 ozone season[12] 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 base case including CPP and illustrative

[9] For the purposes of this analysis non-coal fuels include emissions from natural gas, oil, biomass, municipal waste combustion and waste coal EGUs.

[10] 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).

[11] At the time of this analysis, there were no announced EGU retirements after 2030.

[12] "ozone season NO_X emissions" refer to total NO_X (ton) emitted during the period of May-September.

scenarios 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 "fused surfaces" of measured and modeled air quality[13] 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 base case including CPP 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[14] for the 2025 base case including CPP and the corresponding 2023 SO_2, NO_X, and directly emitted $PM_{2.5}$ emissions to calculate the ratio of 2025 base case emissions to 2023 emissions for each of these pollutant 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 base case including CPP.

(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.[15]

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[13] 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).

[14] The 2025, 2030, and 2035 EGU SO_2 and NO_X emissions for the base case and the four illustrative scenarios were obtained from IPM outputs for these scenarios. 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.

[15] 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.

(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 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 base case including CPP 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)[16] are divided by the corresponding quarterly average species concentrations from the 2011 model run. This step results in a Relative Response Factor (i.e., RRF) between 2011 and the 2025 base case 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 fused surfaces to produce quarterly average species concentrations for the 2025 base case.

(8) The 2025 base case 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 base case that are input to BenMAP-CE.

The steps above are repeated for each of the four illustrative scenarios and each of the 3 analysis years.[17]

For generating the spatial fields for each of the two ozone metrics we follow steps similar to those above for $PM_{2.5}$. Again, we use the 2025 base case 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 base case and the corresponding 2023 OS NO_X emissions to calculate the ratio of 2025 base case emissions to 2023 emissions for each EGU tag (i.e. an ozone-season scaling factor for each tag).

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

[17] 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.

(1) 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).[18] 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 base case.

(2) 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.[19]

(3) 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 base case EGU emissions in each model grid cell, nationwide for each day in the ozone season.

(4) 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.

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

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

As with $PM_{2.5}$, the steps outlined NO_X for ozone are repeated for each of the four illustrative scenarios and each of the 3 analysis years.[20]

[18] 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).
[19] 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.

[20] For 2030 and 2035 analysis years, the contributions from 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 years.

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 quality concentrations between the illustrative scenarios and the base case 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 a 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 causal.

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; the ISA indicated reproductive, developmental, cancer, mutagenicity and genotoxicity outcomes as being suggestive. 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 neurological outcomes. Among chronic effects, the ISA reported a likely-to-be-causal relationship for respiratory outcomes and respiratory mortality, and suggestive relationship for cardiovascular outcomes and reproductive effects. The ISA reported a suggestive relationship for reproductive and neurological effects, and inadequate evidence to determine a relationship for cancer.

The Agency estimates counts of air pollution effects for those endpoints above 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; effects identified as being quantified may not have been quantified completely. 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, level of air pollution to which the population is exposed.

In the example below, 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

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

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

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 $PM_{2.5}$ exposure, C_{ij} is 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.[21]

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 endpoint. $PM_{2.5}$ (and ozone) concentrations are taken from the air pollution spatial surfaces described above in section 4.4.1. Beginning with this RIA, the Agency updated a number of population and baseline incidence input parameters with more recent data. For example, we replaced the baseline rates of age- and cause-stratified death from the Centers for Disease Control and Prevention (CDC) with more recent CDC-supplied data. These data are documented in the appendices to the BenMAP-CE user manual (U.S. EPA 2018c). A memo detailing the

[21] In this illustrative example, the air quality is resolved at the county level. In this analysis, the air quality model predicts air pollutant concentrations at a 12km by 12km grid. 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.

Agency's quality assurance procedures for evaluating these new data and the results of an analysis characterizing the sensitivity of estimated health impacts to using these new input parameters may be found on the BenMAP-CE website (U.S. EPA 2018b).

This health impact assessment quantifies outcomes using a suite of concentration-response parameters described in the PM NAAQS RIA (U.S. EPA 2012b) and Ozone NAAQS RIA (U.S. EPA 2015e). These two RIAs 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.

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

For adult PM-related mortality, we use the effect coefficients from the most recent 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 ACS and Six Cities cohorts produce the strongest evidence of the 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 these two cohorts for analyses of the benefits of PM reductions (U.S. EPA-SAB 2010). As both the ACS and Six Cities cohort studies exhibit both strengths and weaknesses, 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).[22]

Following this approach, we report the forgone $PM_{2.5}$ and ozone-related benefits (in terms of both health impacts and monetized values) for the four illustrative scenarios and for the years 2025, 2030 and 2035, where the $PM_{2.5}$-related forgone benefits are calculated using a log-linear concentration-response function that quantifies risk from the full range of $PM_{2.5}$ 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, "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). 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.[23] To give

[22] 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 mg/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."

[23] 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

insight to the level of uncertainty in the estimated forgone $PM_{2.5}$ mortality benefits at lower ambient levels, we report the PM benefits according to alternative concentration cut-points. Below we further describe our rationale for selecting these cut-points and report a suite of sensitivity analyses. In addition to adult mortality discussed in 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 EPA regarding the procedure for quantifying and valuing ozone-related short-term mortality. 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 the 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). We report the ozone-attributable deaths in this RIA as a range reflecting the concentration-response parameters from these two studies.

4.4.3 Economic Value of Forgone Ancillary Health Co-benefits

We next quantify the economic value of the $PM_{2.5}$ and ozone-related deaths and illnesses estimated above. Changing ambient concentrations of air pollution generally yields a small change 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,

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" 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), 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.

EPA continues work to update its guidance on valuing mortality risk reductions, and the Agency consulted several times with the SAB-EEAC on this issue. Until updated guidance is available, the Agency determined that a single, peer-reviewed estimate applied consistently, best reflects the SAB-EEAC advice it has received. Therefore, EPA applies the VSL that was vetted and endorsed by the SAB in the *Guidelines for Preparing Economic Analyses* (U.S. EPA 2016a) while the Agency continues its efforts to update its guidance on this issue. This approach calculates a mean value across VSL estimates derived from 26 labor market and contingent valuation studies published between 1974 and 1991. The mean VSL across these studies is $6.3 million (2000$).[24] 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.

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

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. 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, 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 Forgone Benefits

This analysis includes many data sources as inputs that are each subject to uncertainty. Input parameters include 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). 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, because $PM_{2.5}$ varies considerably in composition across sources, but the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type. The PM ISA 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)

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 varied concentrations of $PM_{2.5}$, including both areas that do not meet the fine particle standard and those areas that are in attainment, down to the lowest modeled concentrations.

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. Each of the above assumptions are subject to uncertainty.

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

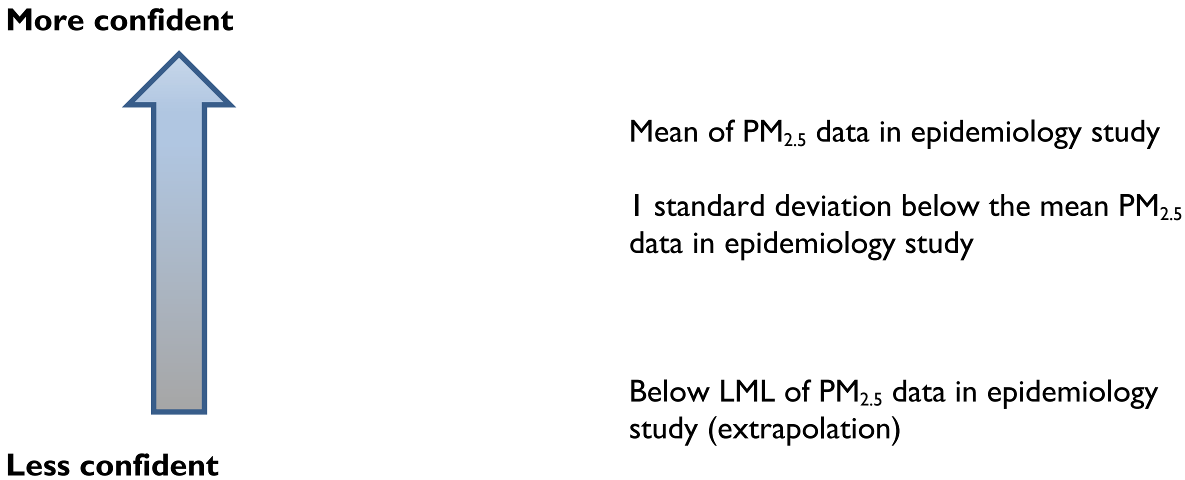

Figure 4-1 Relationship between the $PM_{2.5}$ Concentrations Considered in Epidemiology Studies and our Confidence in the Estimated PM-related Premature Deaths

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., EPA does not view these concentration benchmarks as concentration thresholds below which we would not quantify health co-benefits of air quality improvements.[25] 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 proposal. The PM ISA concluded that the scientific evidence collectively is sufficient to conclude that the relationship between long-term $PM_{2.5}$ exposures and mortality is causal and that overall the

[25] 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).

studies support the use of a no-threshold log-linear model to estimate PM-related long-term mortality (U.S. EPA 2009).

Figure 4-2 and Figure 4-3 report the percentage of the population, and number of PM-related deaths, both above and below concentration benchmarks in the proposed policy modeling for the year 2030. Both figures identify the LML for each of the major cohort studies in orange and the annual mean $PM_{2.5}$ NAAQS of 12 µg/m^3 in red. For Krewski, the LML is 5.8 µg/m^3 and for Lepeule et al., the LML is 8 µg/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 12 µg/m^3 in nearly all locations. The photochemical modeling we employ accounts for the suite of local, state and federal policies expected to reduce $PM_{2.5}$ and $PM_{2.5}$ precursor emissions in future years, 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; Table 4-6;Table 4-7) we stratify these estimated PM 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 4-12). 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, 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* $PM_{2.5}$ levels.

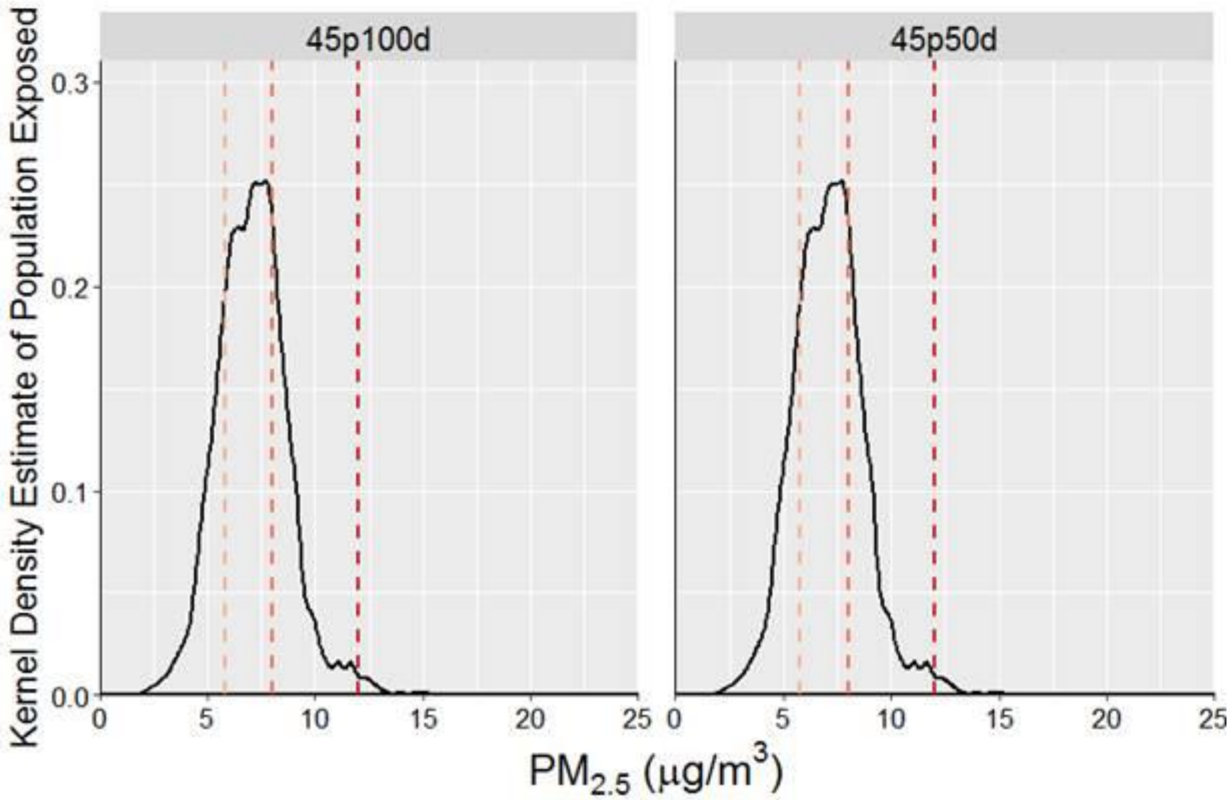

Figure 4-2 Number of Individuals Exposed According to Annual Mean $PM_{2.5}$ Concentration in 2030

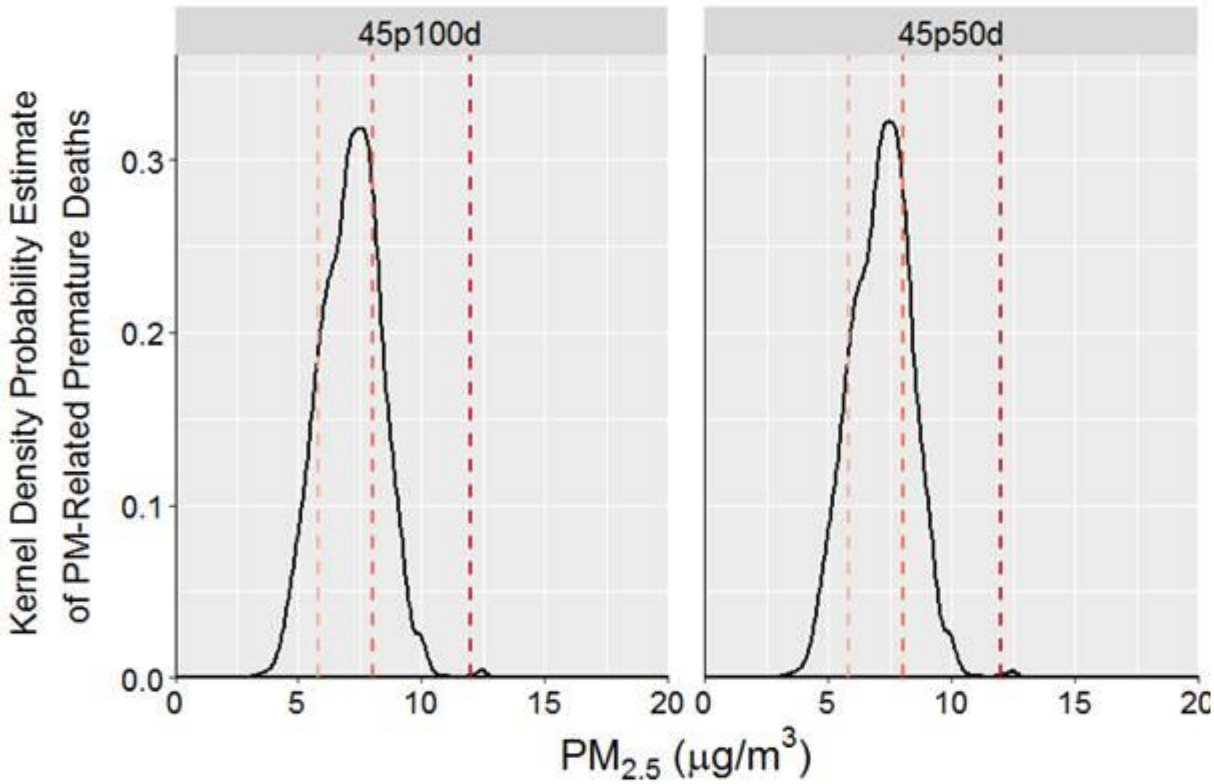

Figure 4-3 Number of $PM_{2.5}$-Related Premature Deaths According to $PM_{2.5}$ Concentration in 2030

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 8hr maximum concentrations for the 2 percent HRI at $50/kW, 4.5 percent HRI at $50/kW, 4.5 percent HRI at $100/kW, and No CPP illustrative scenarios (Figure 4-4). All maps display the change in air pollution calculated as the policy case minus the base case. These spatial fields serve as an input to the benefits analysis, the results of which are described further below.

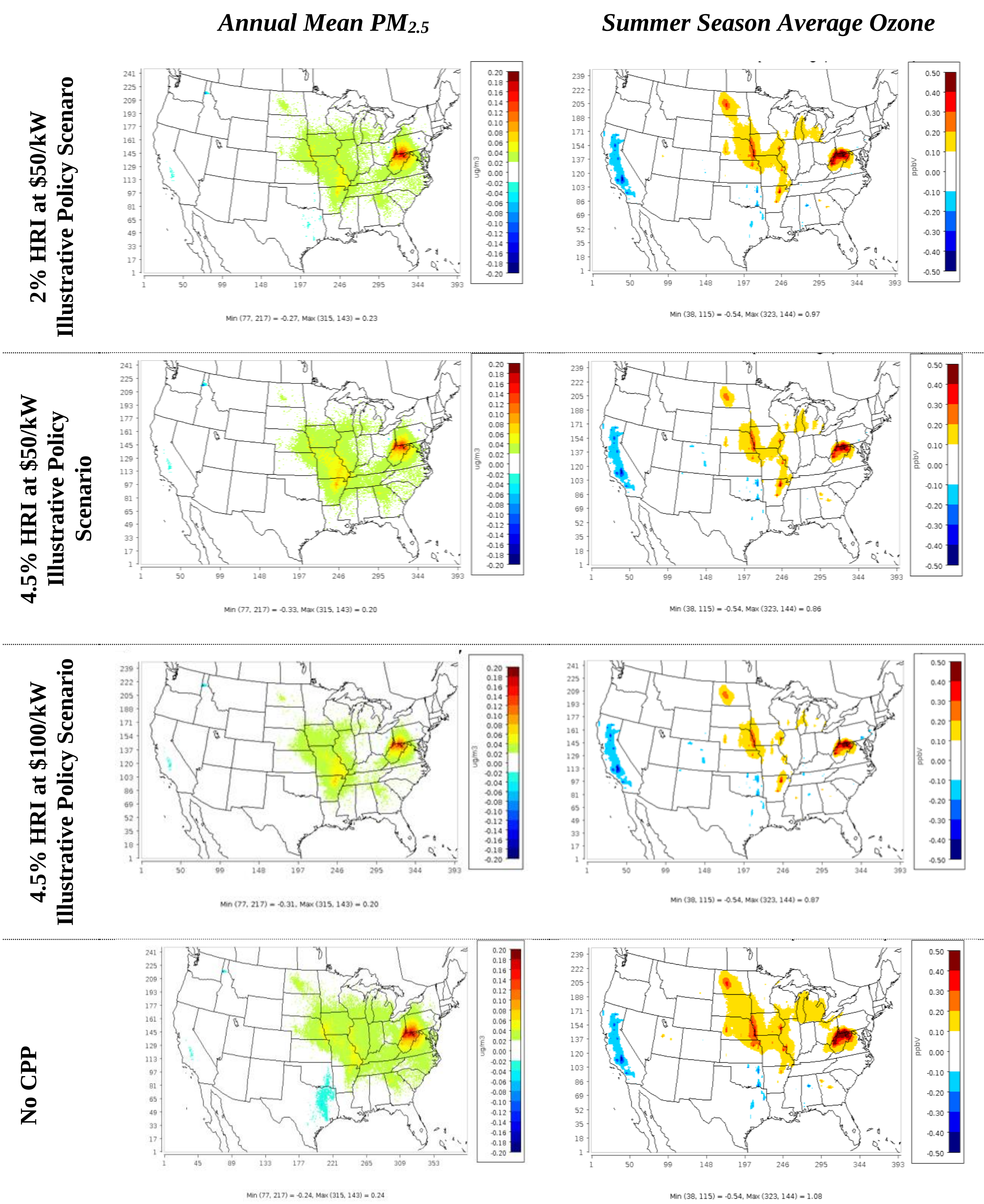

Figure 4-4 Change in Annual Mean $PM_{2.5}$ ($\mu g/m^3$) and Summer Season Average Daily 8hr Maximum Ozone (ppb) in 2025 (Difference Calculated as Illustrative Scenario - Base Case)

4.5.2 Estimated Number and Economic Value of Forgone Ancillary Health Co-Benefits

Below we report the estimated number of forgone PM2.5 and ozone-related premature deaths and illnesses in each year and for each year and illustrative scenario (Table 4-5, Table 4-6, Table 4-7), relative to the base case, which include the CPP. These tables are followed by the estimated number of forgone PM2.5-related premature deaths calculated using different approaches to evaluate uncertainty of the effect of PM2.5 concentrations at lower ambient levels (Table 4-8). We summarize the dollar value of these impacts for each policy scenario across all PM2.5 and ozone-related premature deaths and illnesses, using four alternative approaches to representing and quantifying PM mortality risk effects (Table 4-9, Table 4-10, and Table 4-11). 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. Finally, we display the spatial distribution of the sum of the estimated forgone PM2.5 and ozone-attributable deaths in each year Figure 4-5.

Table 4-5 Estimated Incremental $PM_{2.5}$ and Ozone-Related Premature Deaths and Illnesses in 2025*

		No CPP	2% HRI at $50/kW	4.5% HRI at $50/kW	4.5% HRI at $100/kW
Changes in premature death among adults					
$PM_{2.5}$	Krewski *et al.* (2009)	280 (190 to 370)	260 (170 to 340)	280 (19 to 370)	220 (150 to 300)
$PM_{2.5}$	Lepeule *et al.* (2012)	640 (320 to 960)	590 (290 to 890)	630 (310 to 950)	510 (250 to 760)
Ozone	Smith *et al.* (2009)	11 (6 to 17)	5 (3 to 8)	3 (2 to 5)	-2 (-1 to -3)
Ozone	Jerrett et al. (2009)	41 (14 to 68)	20 (7 to 33)	12 (4 to 20)	-6.5 (-2 to -11)
$PM_{2.5}$- related non-fatal heart attacks among adults					
	Peters et al. (2001)	290 (71 to 510)	270 (66 to 470)	290 (71 to 510)	230 (57 to 410)
	Pooled estimate	32 (12 to 85)	29 (11 to 78)	31 (12 to 84)	25 (9 to 68)
All other morbidity effects					
	Hospital admissions—cardiovascular ($PM_{2.5}$)	72 (32 to 130)	67 (29 to 120)	72 (31 to 130)	58 (25 to 110)
	Hospital admissions—respiratory ($PM_{2.5}$ & O_3)	90 (27 to 170)	75 (27 to 140)	77 (30 to 140)	55 (26 to 100)
	ED visits for asthma ($PM_{2.5}$ & O_3)	190 (-44 to 440)	150 (-44 to 330)	140 (-48 to 310)	84 (-97 to 220)
	Exacerbated asthma ($PM_{2.5}$ & O_3)	23,000 (-15,000 to 56,000)	12,000 (-5,600 to 29,000)	8,600 (-2,200 to 20,000)	-2,200 (-18,000 to 18,000)
	Minor restricted-activity days ($PM_{2.5}$ & O_3)	210,000 (150,000 to 260,000)	170,000 (130,000 to 210,000)	170,000 (140,000 to 210,000)	120,000 (100,000 to 130,000)
	Acute bronchitis ($PM_{2.5}$)	310 (-73 to 700)	290 (-68 to 650)	320 (-75 to 710)	250 (-59 to 560)
	Upper resp. symptoms ($PM_{2.5}$)	5,600 (1,000 to 10,000)	5,300 (960 to 9,600)	5,700 (1,000 to 10,000)	4,600 (830 to 8,300)
	Lower resp. symptoms ($PM_{2.5}$)	4,000 (1,500 to 6,400)	3,700 (1,400 to 6,000)	4,000 (1,500 to 6,500)	3,200 (1,200 to 5,200)
	Lost work days ($PM_{2.5}$)	28,000 (24,000 to 33,000)	26,000 (22,000 to 30,000)	29,000 (24,000 to 33,000)	23,000 (19,000 to 26,000)
	School absence days (O_3)	12,000 (4,400 to 28,000)	4,500 (1,600 to 10,000)	1,500 (540 to 3,400)	-5,400 (-12,000 to -1,900)

* Values rounded to two significant figures

Table 4-6 Estimated Incremental $PM_{2.5}$ and Ozone-Related Premature Deaths and Illnesses in 2030*

		No CPP	2% HRI at $50/kW	4.5% HRI at $50/kW	4.5% HRI at $100/kW
Changes in premature death among adults					
$PM_{2.5}$	Krewski *et al.* (2009)	470 (320 to 630)	410 (280 to 550)	410 (280 to 550)	350 (240 to 470)
	Lepeule *et al.* (2012)	1,100 (540 to 1,600)	940 (470 to 1,400)	940 (470 to 1,400)	800 (400 to 1,200)
Ozone	Smith *et al.* (2009)	24 (12 to 36)	38 (19 to 57)	16 (8 to 25)	12 (6 to 18)
	Jerrett et al. (2009)	86 (29 to 140)	140 (47 to 230)	59 (20 to 98)	43 (14 to 71)
$PM_{2.5}$- related non-fatal heart attacks among adults					
	Peters et al. (2001)	490 (120 to 860)	430 (100 to 750)	430 (110 to 760)	360 (89 to 640)
	Pooled estimate	53 (20 to 140)	46 (17 to 120)	47 (17 to 120)	39 (15 to 110)
All other morbidity effects					
	Hospital admissions—cardiovascular ($PM_{2.5}$)	120 (53 to 230)	110 (46 to 200)	110 (47 to 200)	91 (40 to 170)
	Hospital admissions—respiratory ($PM_{2.5}$ & O_3)	130 (210 to 250)	110 (26 to 210)	140 (35 to 280)	87 (24 to 170)
	ED visits for asthma ($PM_{2.5}$ & O_3)	250 (-50 to 620)	210 (-37 to 530)	280 (-51 to 690)	170 (-34 to 410)
	Exacerbated asthma ($PM_{2.5}$ & O_3)	44,000 (-31,000 to 110,000)	40,000 (-29,000 to 96,000)	48,000 (-34,000 to 120,000)	29,000 (-20,000 to 69,000)
	Minor restricted-activity days ($PM_{2.5}$ & O_3)	290,000 (200,000 to 370,000)	230,000 (160,000 to 310,000)	300,000 (210,000 to 390,000)	190,000 (140,000 to 250,000)
	Acute bronchitis ($PM_{2.5}$)	570 (-130 to 1,300)	500 (-120 to 1,100)	500 (-120 to 1,100)	420 (-99 to 940)
	Upper resp. symptoms ($PM_{2.5}$)	10,000 (1,900 to 19,000)	9,000 (1,600 to 16,000)	9,000 (1,600 to 16,000)	7,700 (1,400 to 14,000)
	Lower resp. symptoms ($PM_{2.5}$)	7,200 (2,800 to 12,000)	6,300 (2,400 to 10,000)	6,300 (2,400 to 10,000)	5,400 (2,000 to 8,700)
	Lost work days ($PM_{2.5}$)	48,000 (40,000 to 55,000)	42,000 (35,000 to 48,000)	42,000 (35,000 to 48,000)	35,000 (30,000 to 41,000)
	School absence days (O_3)	31,000 (11,000 to 71,000)	60,000 (22,000 to 140,000)	21,000 (7,700 to 48,000)	16,000 (5,600 to 35,000)

* Values rounded to two significant figures

Table 4-7 Estimated Incremental $PM_{2.5}$ and Ozone-Related Premature Deaths and Illnesses in 2035*

		No CPP	2% HRI at $50/kW	4.5% HRI at $50/kW	4.5% HRI at $100/kW
Changes in premature death among adults					
$PM_{2.5}$	Krewski *et al.* (2009)	370 (250 to 490)	290 (190 to 380)	380 (260 to 510)	250 (170 to 330)
$PM_{2.5}$	Lepeule *et al.* (2012)	830 (420 to 1,200)	650 (330 to 980)	870 (440 to 1,300)	570 (280 to 850)
Ozone	Smith *et al.* (2009)	19 (9 to 28)	18 (9 to 27)	22 (11 to 33)	12 (6 to 19)
Ozone	Jerrett et al. (2009)	68 (23 to 110)	65 (22 to 110)	81 (27 to 130)	45 (15 to 75)
Non-fatal heart attacks among adults					
	Peters et al. (2001)	390 (95 to 680)	310 (75 to 540)	410 (100 to 720)	270 (65 to 470)
	Pooled estimate	42 (15 to 110)	33 (12 to 89)	44 (16 to 120)	29 (11 to 77)
All other morbidity effects					
	Hospital admissions—cardiovascular ($PM_{2.5}$)	97 (42 to 180)	77 (33 to 140)	100 (44 to 190)	67 (29 to 120)
	Hospital admissions—respiratory ($PM_{2.5}$ & O_3)	130 (-8 to 250)	110 (26 to 210)	140 (35 to 280)	87 (24 to 170)
	ED visits for asthma ($PM_{2.5}$ & O_3)	250 (-50 to 620)	210 (-37 to 530)	280 (-51 to 690)	170 (-34 to 410)
	Exacerbated asthma ($PM_{2.5}$ & O_3)	44,000 (-31,000 to 110,000)	40,000 (-29,000 to 96,000)	48,000 (-34,000 to 120,000)	29,000 (-20,000 to 69,000)
	Minor restricted-activity days ($PM_{2.5}$ & O_3)	290,000 (200,000 to 370,000)	230,000 (160,000 to 310,000)	300,000 (210,000 to 390,000)	190,000 (140,000 to 250,000)
	Acute bronchitis ($PM_{2.5}$)	430 (-100 to 960)	330 (-78 to 740)	440 (-100 to 980)	290 (-69 to 650)
	Upper resp. symptoms ($PM_{2.5}$)	7,800 (1,400 to 14,000)	6,100 (1,100 to 11,000)	8,000 (1,500 to 15,000)	5,300 (960 to 9,700)
	Lower resp. symptoms ($PM_{2.5}$)	5,500 (2,100 to 8,900)	4,200 (1,600 to 6,900)	5,600 (2,100 to 9,100)	3,700 (1,400 to 6,000)
	Lost work days ($PM_{2.5}$)	36,000 (31,000 to 42,000)	28,000 (24,000 to 32,000)	37,000 (31,000 to 43,000)	24,000 (21,000 to 28,000)
	School absence days (O_3)	16,000 (5,900 to 37,000)	24,000 (8,600 to 54,000)	29,000 (10,000 to 64,000)	16,000 (5,900 to 37,000)

* Values rounded to two significant figures

Table 4-8 PM-Related Premature Deaths Estimated Using Alternative Approaches to Evaluate Uncertainty at Low-Concentations (95% Confidence Interval), Relative to Base Case (CPP)*

	No CPP	2% HRI at $50/kW	4.5% HRI at $50/kW	4.5% HRI at $100/kW
2025				
Log-Linear no-threshold model				
Krewski *et al.* (2009)	280 (190 to 370)	260 (170 to 340)	280 (190 to 370)	220 (150 to 300)
Lepeule *et al.* (2012)	640 (320 to 960)	590 (290 to 890)	630 (310 to 950)	510 (250 to 760)
Assuming PM effects below the LML of each study fall to zero				
Krewski *et al.* (2009) (LML= 5.8 μg/m^3)	240 (160 to 310)	220 (150 to 290)	230 (160 to 310)	190 (130 to 250)
Lepeule *et al.* (2012) (LML=8μg/m^3)	140 (67 to 200)	130 (64 to 190)	150 (74 to 220)	110 (57 to 170)
2030				
Log-Linear no-threshold model				
Krewski *et al.* (2009)	470 (320 to 630)	410 (280 to 550)	410 (280 to 550)	350 (240 to 470)
Lepeule *et al.* (2012)	1,100 (540 to 1,600)	940 (470 to 1,400)	940 (470 to 1,400)	800 (400 to 1,200)
Assuming PM effects below the LML of each study fall to zero				
Krewski *et al.* (2009) (LML= 5.8 μg/m^3)	400 (270 to 530)	350 (240 to 460)	350 (240 to 460)	300 (200 to 390)
Lepeule *et al.* (2012) (LML=8μg/m^3)	260 (130 to 380)	220 (110 to 330)	220 (110 to 330)	180 (92 to 280)
2035				
Log-Linear no-threshold model				
Krewski *et al.* (2009)	370 (250 to 490)	290 (190 to 380)	380 (260 to 510)	250 (170 to 330)
Lepeule *et al.* (2012)	830 (420 to 1,200)	650 (330 to 980)	870 (440 to 1,300)	570 (280 to 850)
Assuming PM effects below the LML of each study fall to zero				
Krewski *et al.* (2009) (LML= 5.8 μg/m^3)	320 (220 to 420)	250 (170 to 330)	330 (220 to 440)	220 (150 to 290)
Lepeule *et al.* (2012) (LML=8μg/m^3)	220 (110 to 330)	170 (83 to 250)	210 (110 to 320)	150 (73 to 220)

* Values rounded to two significant figures

Table 4-9 Estimated Economic Value of Incremental $PM_{2.5}$ and Ozone-Attributable Deaths and Illnesses for Illustrative Scenarios & Three Alternative Approaches to Representing PM Effects in 2025, Relative to Base Case (CPP) (95% Confidence Interval; Billions of 2016$)[A]

		No CPP			2% HRI at $50/kW			4.5% HRI at $50/kW			4.5% HRI at $100/kW		
Ozone benefits summed with PM benefits:													
3% Discount Rate	No-threshold model[B]	$2.8 ($0.3 to $7.7)	*to*	$6.6 ($0.6 to $19)	$2.6 ($0.3 to $7)	*to*	$5.9 ($0.5 to $17)	$2.7 ($0.3 to $7.4)	*to*	$6.2 ($0.6 to $18)	$2.1 ($0.2 to $5.9)	*to*	$4.9 ($0.2 to $14)
3% Discount Rate	Limited to above LML[C]	$1.8 ($0.1 to $5.2)	*to*	$2.4 ($0.1 to $7)	$1.5 ($0.1 to $4)	*to*	$2.2 ($0.2 to $6)	$1.6 ($0.2 to $4.6)	*to*	$2.3 ($0.2 to $6)	$1.1 (-$.1 to $3.3)	*to*	$1.8 ($0.1 to $5)
3% Discount Rate	Effects above NAAQS[D]	$0.12 ($0 to $0.4)	*to*	$0.4 ($0 to $1.3)	$0.06 ($0 to $0.2)	*to*	$0.21 ($0 to $0.6)	$0.04 ($0 to $0.1)	*to*	$0.12 ($0 to $0.4)	-$0.07 (-$0.2 to -$0)	*to*	-$0.02 (-$0.1 to $0)
Ozone benefits summed with PM benefits:													
7% Discount Rate	No-threshold model[B]	$2.6 ($0.3 to $7)	*to*	$6.1 ($0.6 to $17)	$2.4 ($0.2 to $6.4)	*to*	$5.4 ($0.5 to $15)	$2.5 ($0.2 to $6.7)	*to*	$5.7 ($0.5 to $16)	$2 ($0.1 to $5.4)	*to*	$4.4 ($0.2 to $13)
7% Discount Rate	LML model[C]	$1.7 ($0 to $5)	*to*	$2.2 ($0.1 to $6)	$1.4 ($0.1 to $4)	*to*	$2 ($0.2 to $5)	$1.5 ($0.1 to $4.2)	*to*	$2.1 ($0.2 to $6)	$0.99 (-$0.1 to $3)	*to*	$1.7 ($0 to $4.6)
7% Discount Rate	Effects above NAAQS[D]	$0.12 ($0 to $0.4)	*to*	$0.43 ($0 to $1.3)	$0.06 ($0 to $0.2)	*to*	$0.21 ($0 to $0.6)	$0.04 ($0 to $0.1)	*to*	$0.12 ($0 to $0.4)	-$0.07 (-$0.2 to -$0)	*to*	-$0.02 (-$0.1 to $0)

[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).

[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 Lepeule et al. (2012) study (8 µg/m^3); high end of range reflects dollar value of effects quantified down to LML of Krewski et al. (2009) study (5.8 µg/m^3).

[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.

Table 4-10 Estimated Economic Value of Forgone $PM_{2.5}$ and Ozone-Attributable Deaths and Illnesses for Illustrative Scenarios & Three Alternative Approaches to Representing PM Effects in 2030, Relative to Base Case (CPP) (95% Confidence Interval; Billions of 2016$)[A]

		No CPP			2% HRI at $50/kW			4.5% HRI at $50/kW			4.5% HRI at $100/kW		
Ozone benefits summed with PM benefits:													
3% Discount Rate	No-threshold model[B]	$4.9 ($0.47 to $13)	*to*	$11 ($1 to $33)	$4.5 ($0.4 to $12)	*to*	$11 ($1 to $30)	$4.2 ($0.4 to $11)	*to*	$9.8 ($0.9 to $28)	$3.6 ($0.34 to $9.7)	*to*	$8.2 ($0.8 to $24)
	LML model[C]	$3.5 ($0.33 to $10)	*to*	$4.2 ($0.4 to $11)	$3.7 ($0.3 to $11)	*to*	$3.8 ($0.4 to $10)	$2.9 ($0.3 to $8.3)	*to*	$3.6 ($0.4 to $10)	$2.3 ($0.22 to $6.7)	*to*	$3 ($0.3 to $8)
	Effects above NAAQS[D]	$0.26 ($0 to $0.75)	*to*	$0.92 ($0 to $2.7)	$0.43 ($0 to $1.2)	*to*	$1.5 ($0.1 to $4)	$0.18 ($0 to $0.5)	*to*	$0.63 ($0.1 to $1.9)	$0.13 ($0 to $0.4)	*to*	$0.46 ($0 to $1.4)
Ozone benefits summed with PM benefits:													
7% Discount Rate	No-threshold model[B]	$4.5 ($0.43 to $12)	*to*	$10 ($1 to $30)	$4.1 ($0.4 to $11)	*to*	$9.8 ($0.9 to $28)	$3.9 ($0.4 to $11)	*to*	$9 ($0.8 to $26)	$3.3 ($0.3 to $8.9)	*to*	$7.6 ($0.7 to $22)
	LML model[C]	$3.3 ($0.3 to $9.4)	*to*	$3.8 ($0.4 to $10)	$3.5 ($0.3 to $9.7)	*to*	$3.5 ($0.3 to $10)	$3.3 ($0.32 to $9)	*to*	$2.7 ($0.3 to $7.7)	$2.2 ($0.2 to $6.2)	*to*	$2.8 ($0.3 to $8)
	Effects above NAAQS[D]	$0.26 ($0 to $0.8)	*to*	$0.92 ($0.1 to $3)	$0.43 ($.04 to $1.2)	*to*	$1.5 ($0.1 to $4)	$0.18 ($0 to $0.5)	*to*	$0.63 ($0.1 to $2)	$0.13 ($0 to $0.4)	*to*	$0.46 ($0 to $1.4)

[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).

[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 Lepeule et al. (2012) study (8 $\mu g/m^3$); high end of range reflects dollar value of effects quantified down to LML of Krewski et al. (2009) study (5.8 $\mu g/m^3$).

[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.

Table 4-11 Estimated Economic Value of Forgone $PM_{2.5}$ and Ozone-Attributable Deaths and Illnesses for Illustrative Scenarios & Three Alternative Approaches to Representing PM Effects in 2035, Relative to Base Case (CPP) (95% Confidence Interval; Billions of 2016$)[A]

		No CPP			2% HRI at $50/kW			4.5% HRI at $50/kW			4.5% HRI at $100/kW		
Ozone benefits summed with PM benefits:													
3% Discount Rate	No-threshold model[B]	$3.8 ($0.4 to $10)	*to*	$8.8 ($1 to $25)	$3 ($0.29 to $8.1)	*to*	$7 ($0.6 to $20)	$4 ($0.4 to $11)	*to*	$9.3 ($1 to $27)	$2.6 ($0.25 to $7)	*to*	$6 ($1 to $17)
	LML model[C]	$2.9 ($0.3 to $8.4)	*to*	$3.3 ($0.3 to $9)	$2.4 ($0.2 to $7)	*to*	$2.6 ($0.3 to $7)	$3 ($0.3 to $8.6)	*to*	$3.5 ($0.3 to $9)	$2 ($0.2 to $6)	*to*	$2.3 ($0.2 to $6)
	Effects above NAAQS[D]	$0.21 ($0 to $0.6)	*to*	$0.73 ($0.1 to $2)	$0.2 ($0 to $0.6)	*to*	$0.69 ($0.1 to $2)	$0.24 ($0 to $0.7)	*to*	$0.86 ($0.1 to $3)	$0.14 ($0 to $0.4)	*to*	$0.48 ($0 to $1)
Ozone benefits summed with PM benefits:													
7% Discount Rate	No-threshold model[B]	$3.5 ($0.3 to $9)	*to*	$8.1 ($1 to $23)	$2.7 ($0.3 to $8)	*to*	$6.5 ($1 to $19)	$3.7 ($0.4 to $10)	*to*	$8.6 ($1 to $25)	$2.4 ($0.2 to $6)	*to*	$5.5 ($1 to $16)
	LML model[C]	$2.7 ($0.3 to $8)	*to*	$3 ($0.3 to $8)	$2.2 ($0.2 to $6.4)	*to*	$2.4 ($0.2 to $7)	$2.8 ($0.26 to $8)	*to*	$3.2 ($0.3 to $9)	$1.8 ($0.17 to $5.3)	*to*	$2.1 ($0.2 to $6)
	Effects above NAAQS[D]	$0.21 ($0 to $0.6)	*to*	$0.73 ($0.1 to $2)	$0.2 ($0 to $0.6)	*to*	$0.69 ($0.1 to $2)	$0.24 ($0 to $0.7)	*to*	$0.86 ($0.1 to $3)	$0.14 ($0 to $0.4)	*to*	$0.48 ($0 to $1)

[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).

[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 Lepeule et al. (2012) study (8 $\mu g/m^3$); high end of range reflects dollar value of effects quantified down to LML of Krewski et al. (2009) study (5.8 $\mu g/m^3$).

[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.

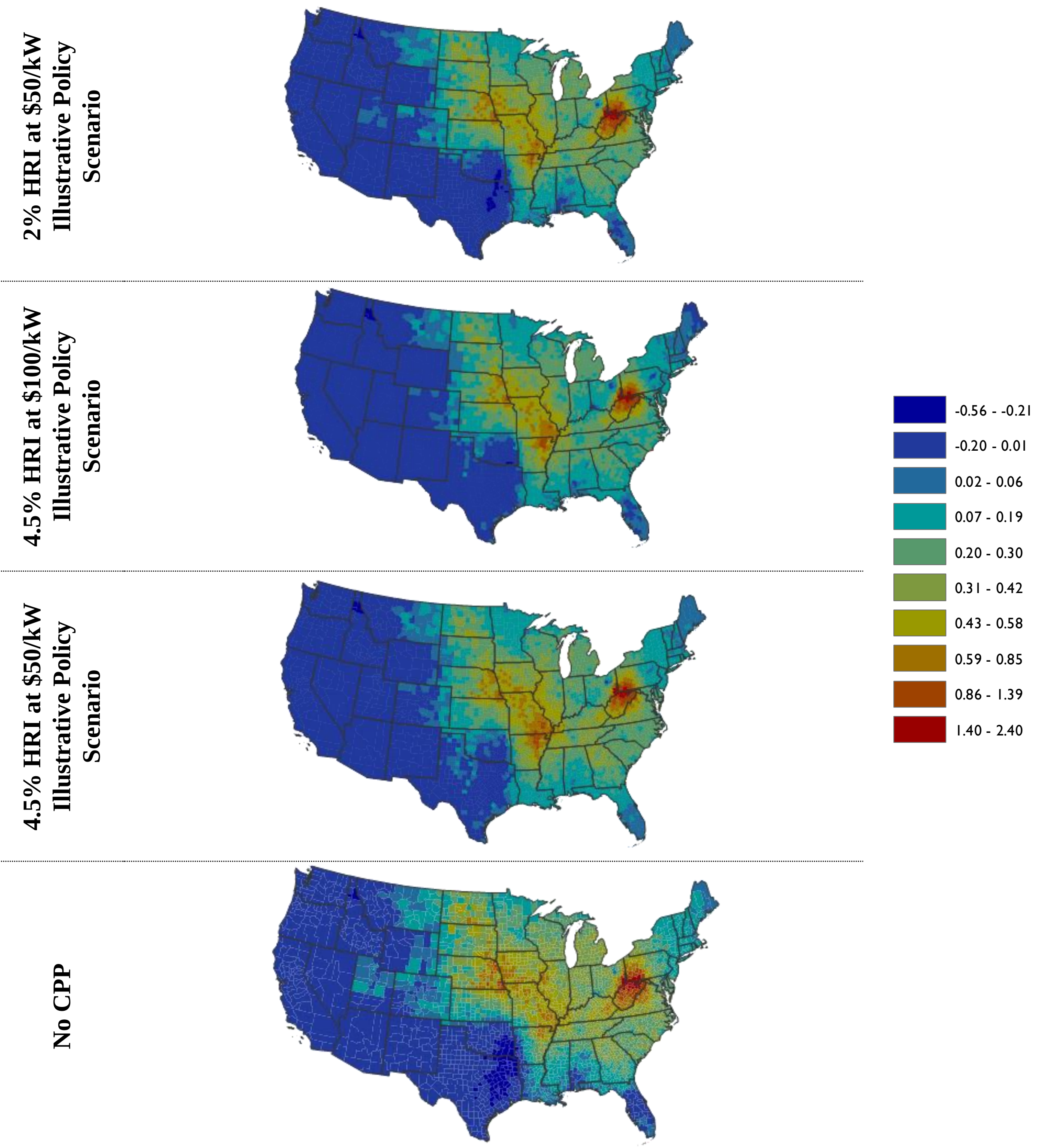

Figure 4-5 Estimated Forgone Avoided $PM_{2.5}$ and Ozone Deaths for Each Illustrative Scenario in 2025, Relative to Base Case (CPP) (Deaths per 100k People)

Table 4-12 Estimated Percent of $PM_{2.5}$-related Premature Deaths Above and Below $PM_{2.5}$ Concentration Cut Points

Year	Policy option	Epidemiological study	Total mortality	$PM_{2.5}$-related premature deaths reported by air quality cutpoint: *Above NAAQS*	*Below NAAQS and Above LML* [A]	*Below LML* [A]
2025	No CPP	Krewski	280	<1 *(<1%)*	240 *(84%)*	44 *(16%)*
		Lepeule	640	<1 *(<1%)*	140 *(21%)*	510 *(79%)*
	2% HRI @ $50/kW	Krewski	260	<1 *(<1%)*	220 *(84%)*	41 *(16%)*
		Lepeule	590	<1 *(<1%)*	130 *(22%)*	460 *(78%)*
	4.5% HRI @ $50/kW	Krewski	280	<1 *(<1%)*	230 *(85%)*	42 *(15%)*
		Lepeule	630	<1 *(<1%)*	150 *(23%)*	480 *(77%)*
	4.5% HRI @ $100/kW	Krewski	220	<1 *(<1%)*	190 *(85%)*	34 *(15%)*
		Lepeule	510	<1 *(<1%)*	110 *(23%)*	390 *(77%)*
2030	No CPP	Krewski	470	<1 *(<1%)*	400 *(85%)*	71 *(15%)*
		Lepeule	1,100	2 *(<1%)*	240 *(22%)*	840 *(78%)*
	2% HRI @ $50/kW	Krewski	410	0.7 *(<1%)*	350 *(84%)*	64 *(16%)*
		Lepeule	940	1.6 *(<1%)*	210 *(22%)*	730 *(78%)*
	4.5% HRI @ $50/kW	Krewski	410	0.79 *(<1%)*	350 *(84%)*	66 *(16%)*
		Lepeule	940	1.8 *(<1%)*	210 *(22%)*	740 *(78%)*
	4.5% HRI @ $100/kW	Krewski	350	0.5 *(<1%)*	290 *(84%)*	57 *(16%)*
		Lepeule	800	1.2 *(<1%)*	180 *(22%)*	630 *(78%)*
2030	No CPP	Krewski	370	1 *(<1%)*	320 *(87%)*	48 *(13%)*
		Lepeule	830	2.1 *(<1%)*	180 *(22%)*	650 *(78%)*
	2% HRI @ $50/kW	Krewski	290	0.8 *(<1%)*	250 *(87%)*	37 *(13%)*
		Lepeule	650	2 *(<1%)*	140 *(22%)*	510 *(78%)*
	4.5% HRI @ $50/kW	Krewski	380	1 *(<1%)*	330 *(86%)*	54 *(14%)*
		Lepeule	870	2.3 *(<1%)*	190 *(22%)*	680 *(78%)*
	4.5% HRI @ $100/kW	Krewski	250	0.8 *(<1%)*	220 *(87%)*	32 *(13%)*
		Lepeule	570	1.8 *(<1%)*	130 *(22%)*	440 *(78%)*

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

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. Likewise, we estimate a greater percentage of PM-related deaths below the LML of the Lepeule et al. (2012) study than we do the Krewski et al. (2009) study. 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 Forgone 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 4-13 through Table 4-16 report the combined forgone domestic climate benefits, and forgone health co-benefits discounted at rates of 3 percent and 7 percent for the four illustrative scenarios evaluated for each analysis year: 2025, 2030, and 2035.

Table 4-13 Forgone Climate Benefits and Ancillary Health Co-Benefits, Relative to Base Case (CPP) (billion 2016$)

	Values Calculated using 3% Discount Rate			Values Calculated using 7% Discount Rate		
	Forgone Domestic Climate Benefits	Forgone Health Co-Benefits	Total Forgone Benefits	Forgone Domestic Climate Benefits	Forgone Health Co-Benefits	Total Forgone Benefits
No CPP						
2025	0.3	2.8 to 6.6	3.2 to 7.0	0.1	2.6 to 6.1	2.7 to 6.1
2030	0.5	4.9 to 11.4	5.4 to 11.9	0.1	4.5 to 10.5	4.6 to 10.6
2035	0.5	3.8 to 8.8	4.3 to 9.3	0.1	3.5 to 8.1	3.6 to 8.2
2% HRI at $50/kW						
2025	0.2	2.6 to 5.9	2.8 to 6.2	0.0	2.4 to 5.4	2.4 to 5.5
2030	0.4	4.5 to 10.6	4.9 to 11.0	0.1	4.1 to 9.8	4.2 to 9.9
2035	0.4	3.0 to 7.0	3.4 to 7.4	0.1	2.7 to 6.5	2.8 to 6.6
4.5% HRI at $50/kW						
2025	0.2	2.7 to 6.2	2.9 to 6.4	0.0	2.5 to 5.7	2.5 to 5.7
2030	0.4	4.2 to 9.8	4.6 to 10.2	0.1	3.9 to 9.0	3.9 to 9.1
2035	0.5	4.0 to 9.3	4.4 to 9.8	0.1	3.7 to 8.6	3.7 to 8.7
4.5% HRI at $100/kW						
2025	0.1	2.1 to 4.9	2.3 to 5.0	0.0	2.0 to 4.4	2.0 to 4.4
2030	0.3	3.6 to 8.2	3.9 to 8.6	0.1	3.3 to 7.6	3.3 to 7.6
2035	0.3	2.6 to 6.0	2.9 to 6.3	0.1	2.4 to 5.5	2.4 to 5.6

Notes: Estimates rounded to one decimal point, so figures may not sum due to independent rounding. The forgone 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. Forgone 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 Zanobetti & Schwartz. (2008)). The forgone health co-benefits do not account for direct exposure to NO_2, SO_2, and HAP; ecosystem effects; or, visibility impairment.

Table 4-14 Forgone Climate Benefits and Ancillary Health Co-Benefits, showing only $PM_{2.5}$ Related Benefits above the Lowest Measured Level of Each Long-Term $PM_{2.5}$ Mortality Study, Relative to Base Case (CPP) (billion 2016$)

	Values Calculated using 3% Discount Rate							Values Calculated using 7% Discount Rate						
	Forgone Domestic Climate Benefits	Forgone Health Co-Benefits			Total Forgone Benefits			Forgone Domestic Climate Benefits	Forgone Health Co-Benefits			Total Forgone Benefits		
No CPP														
2025	0.3	2.4	to	1.8	2.8	to	2.1	0.1	2.2	to	1.7	2.3	to	1.7
2030	0.5	4.2	to	3.5	4.7	to	4.0	0.1	3.8	to	3.3	3.9	to	3.4
2035	0.5	3.3	to	2.9	3.8	to	3.4	0.1	3.0	to	2.7	3.1	to	2.8
2% HRI at $50/kW														
2025	0.2	2.2	to	1.5	2.4	to	1.7	0.0	2.0	to	1.4	2.0	to	1.4
2030	0.4	3.8	to	3.7	4.3	to	4.1	0.1	3.5	to	3.5	3.6	to	3.6
2035	0.4	2.6	to	2.4	3.1	to	2.8	0.1	2.4	to	2.2	2.5	to	2.3
4.5% HRI at $50/kW														
2025	0.2	2.3	to	1.6	2.5	to	1.8	0.0	2.1	to	1.5	2.1	to	1.5
2030	0.4	3.6	to	2.9	4.0	to	3.3	0.1	3.3	to	2.7	3.4	to	2.8
2035	0.5	3.5	to	3.0	3.9	to	3.5	0.1	3.2	to	2.8	3.3	to	2.9
4.5% HRI at $100/kW														
2025	0.1	1.8	to	1.1	1.9	to	1.2	0.0	1.7	to	1.0	1.7	to	1.0
2030	0.3	3.0	to	2.3	3.4	to	2.7	0.1	2.8	to	2.2	2.8	to	2.2
2035	0.3	2.3	to	2.0	2.6	to	2.3	0.1	2.1	to	1.8	2.1	to	1.9

Notes: Estimates rounded to one decimal point, so figures may not sum due to independent rounding. The forgone 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. Forgone 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 Zanobetti & Schwartz. (2008)). The forgone health co-benefits do not account for direct exposure to NO_2, SO_2, and HAP; ecosystem effects; or, visibility impairment.

Table 4-15 Forgone Climate Benefits and Ancillary Health Co-Benefits, showing only $PM_{2.5}$ Related Benefits above $PM_{2.5}$ National Ambient Air Quality Standard (billion 2016$)

	Values Calculated using 3% Discount Rate			Values Calculated using 7% Discount Rate		
	Forgone Domestic Climate Benefits	Forgone Health Co-Benefits	Total Forgone Benefits	Forgone Domestic Climate Benefits	Forgone Health Co-Benefits	Total Forgone Benefits
No CPP						
2025	0.3	0.1 to 0.4	0.4 to 0.8	0.1	0.1 to 0.4	0.2 to 0.5
2030	0.5	0.3 to 0.9	0.8 to 1.4	0.1	0.3 to 0.9	0.4 to 1.0
2035	0.5	0.2 to 0.7	0.7 to 1.2	0.1	0.2 to 0.7	0.3 to 0.8
2% HRI at $50/kW						
2025	0.2	0.1 to 0.2	0.3 to 0.4	0.0	0.1 to 0.2	0.1 to 0.3
2030	0.4	0.4 to 1.5	0.9 to 1.9	0.1	0.4 to 1.5	0.5 to 1.6
2035	0.4	0.2 to 0.7	0.6 to 1.1	0.1	0.2 to 0.7	0.3 to 0.8
4.5% HRI at $50/kW						
2025	0.2	0.0 to 0.1	0.2 to 0.3	0.0	0.0 to 0.1	0.1 to 0.2
2030	0.4	0.2 to 0.6	0.6 to 1.1	0.1	0.2 to 0.6	0.3 to 0.7
2035	0.5	0.2 to 0.9	0.7 to 1.3	0.1	0.2 to 0.9	0.3 to 0.9
4.5% HRI at $100/kW						
2025	0.1	(0.0) to (0.1)	0.1 to 0.1	0.0	(0.0) to (0.1)	(0.0) to (0.0)
2030	0.3	0.1 to 0.5	0.5 to 0.8	0.1	0.1 to 0.5	0.2 to 0.5
2035	0.3	0.1 to 0.5	0.5 to 0.8	0.1	0.1 to 0.5	0.2 to 0.5

Notes: Estimates rounded to one decimal point, so figures may not sum due to independent rounding. The forgone 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. Forgone 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 Zanobetti & Schwartz. (2008)). The forgone health co-benefits do not account for direct exposure to NO_2, SO_2, and HAP; ecosystem effects; or, visibility impairment.

Table 4-16 Forgone Climate Benefits and Ancillary Health Co-Benefits using Alternate Method for Representing $PM_{2.5}$ Benefits at Low Levels, Relative to Base Case (CPP) (billion 2016$)

	Values Calculated using 3% Discount Rate			Values Calculated using 7% Discount Rate		
	Forgone Domestic Climate Benefits	Forgone Health Co-Benefits	Total Forgone Benefits	Forgone Domestic Climate Benefits	Forgone Health Co-Benefits	Total Forgone Benefits
No CPP						
2025	0.3	5.5	5.8	0.1	5.0	5.1
2030	0.5	9.3	9.8	0.1	8.5	8.6
2035	0.5	7.2	7.8	0.1	6.6	6.7
2% HRI at $50/kW						
2025	0.2	5.0	5.2	0.0	4.6	4.6
2030	0.4	8.3	8.7	0.1	7.6	7.7
2035	0.4	5.7	6.2	0.1	5.2	5.3
4.5% HRI at $50/kW						
2025	0.2	5.3	5.5	0.0	4.8	4.9
2030	0.4	8.1	8.5	0.1	7.4	7.5
2035	0.5	7.6	8.1	0.1	7.0	7.0
4.5% HRI at $100/kW						
2025	0.1	4.2	4.4	0.0	3.9	3.9
2030	0.3	6.8	7.2	0.1	6.3	6.3
2035	0.3	4.9	5.3	0.1	4.5	4.6

Notes: Estimates rounded to two one decimal point, so figures may not sum due to independent rounding. The forgone 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. Forgone 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 Zanobetti & Schwartz. (2008)). The forgone health co-benefits do not account for direct exposure to NO_2, SO_2, and HAP; ecosystem effects; or, visibility impairment.

4.7 Forgone Ancillary Co-Benefits Not Quantified

The forgone monetized co-benefits estimated above are a subset of those we expect to occur. Data, time, and resource limitations prevented EPA from quantifying the impacts to, or monetizing the co-benefits from, several important benefit categories; these include forgone 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 4-17).

Table 4-17 Unquantified Forgone 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, 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 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).[1] Many of the peer-reviewed articles cited in this section are publications originally cited in the Mercury Study.[2] In addition, 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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[1] National Research Council (NRC). 2000. *Toxicological Effects of Methylmercury*. Washington, DC: National Academies Press.

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

Additional cardiovascular studies have been published since 2000. 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.[3] 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).[4] 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)[5] and in IRIS (U.S. EPA 2002).[6] The existing evidence supporting the possibility of carcinogenic effects

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[3] 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.

[4] 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.

[5] 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).

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.[7] Concentrations in typical human exposure environments are much lower than these levels and rarely exceed the reference concentration.[8]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

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[6] 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.

[7] 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.

[8] 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.[9]

4.7.2 Forgone 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 2008a) 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 Forgone 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 exposure to SO_2 (U.S. EPA 2008c). The immediate effect of SO_2 on the respiratory system in

[9] 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.

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 Forgone 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 2008b), 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 2008b).

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 2008b).

Reductions in emissions of NO_2 and SO_2 will improve the level of visibility throughout the United States because these gases (and the particles of nitrate and sulfate formed from these gases) impair visibility by scattering and absorbing light (U.S. EPA 2009). Visibility is also referred to as visual air quality (VAQ), and it directly affects people's enjoyment of a variety of daily activities (U.S. EPA 2009). Good visibility increases quality of life where individuals live and work, and where they travel for recreational activities, including sites of unique public value, such as the Great Smoky Mountains National Park (U.S. EPA 2009).

4.7.5 Forgone 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 Forgone Carbon Monoxide Co-Benefits

CO in ambient air is formed primarily by the incomplete combustion of carbon-containing fuels and photochemical reactions in the atmosphere. The amount of CO emitted from these reactions, relative to carbon dioxide (CO_2), is sensitive to conditions in the combustion zone, such as fuel oxygen content, burn temperature, or mixing time. Upon inhalation, CO diffuses through the respiratory system to the blood, which can cause hypoxia (reduced oxygen availability). Carbon monoxide can elicit a broad range of effects in multiple tissues and organ systems that depend on concentration and duration of exposure. The *Integrated Science Assessment for Carbon Monoxide* (U.S. EPA 2010a) concluded that short-term exposure to CO is “likely to have a causal relationship” with cardiovascular morbidity, particularly in individuals with coronary heart disease. Epidemiologic studies associate short-term CO exposure with increased risk of emergency department visits and hospital admissions. Coronary heart disease includes those who have angina pectoris (cardiac chest pain), as well as those who have experienced a heart attack. Other subpopulations potentially at risk include individuals with diseases such as chronic obstructive pulmonary disease (COPD), anemia, or diabetes, and individuals in very early or late life stages, such as older adults or the developing young. The evidence is suggestive of a causal relationship between short-term exposure to CO and respiratory morbidity and mortality. The evidence is also suggestive of a causal relationship for birth outcomes and developmental effects following long-term exposure to CO, and for central nervous system effects linked to short- and long-term exposure to CO.

4.7.7 Forgone Visibility Impairment Co-Benefits

Reducing secondary formation of $PM_{2.5}$ would improve levels 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). Without air quality modeling, we are unable to estimate visibility related benefits, and we are also unable to determine whether the emission reductions associated with the final emission guidelines would be likely to have a significant impact on visibility in urban areas or Class I areas.

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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 proposal. 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 the emission guidelines of either the 2015 CPP or this proposal, states are not required to use any of the measures that EPA determines constitute BSER, or use those measures to the same degree of stringency that EPA determines is achievable at reasonable cost. Rather, CAA section 111(d) allows each state to determine the appropriate combination of, and the extent of its reliance on, measures for its state plan. Given the flexibilities afforded states in complying with the emission guidelines under 111(d), the benefits, cost and economic impacts reported in this RIA are illustrative of actions that states 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 proposed guidelines, EPA modeled illustrative policy scenarios. Chapter 1 and Chapter 3 describe the illustrative policy scenarios analyzed. This chapter provides a quantitative assessment of the energy price impacts for these illustrative policy scenarios 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 resulting from the illustrative policy scenarios.

Table 5-1 Summary of Certain Energy Market Impacts, Relative to Base Case (CPP) (Percent Change)

	2025	2030	2035
No CPP			
Retail electricity prices	-0.5%	-0.4%	-0.1%
Average price of coal delivered to the power sector	-0.1%	-0.2%	-0.4%
Coal production for power sector use	6.1%	9.2%	9.5%
Price of natural gas delivered to power sector	-1.1%	-0.3%	0.1%
Price of average Henry Hub (spot)	-1.4%	-0.8%	-0.2%
Natural gas use for electricity generation	-1.5%	-1.5%	-0.9%
2% HRI at $50/kW			
Retail electricity prices	-0.3%	-0.2%	-0.1%
Average price of coal delivered to the power sector	0.2%	-0.1%	-0.4%
Coal production for power sector use	5.5%	8.0%	8.4%
Price of natural gas delivered to power sector	-1.1%	-0.9%	-0.4%
Price of average Henry Hub (spot)	-1.4%	-1.3%	-0.6%
Natural gas use for electricity generation	-2.5%	-1.7%	-1.1%
4.5% HRI at $50/kW			
Retail electricity prices	-0.5%	-0.4%	-0.2%
Average price of coal delivered to the power sector	0.7%	0.6%	0.3%
Coal production for power sector use	5.8%	8.6%	9.5%
Price of natural gas delivered to power sector	-1.4%	-1.1%	-0.7%
Price of average Henry Hub (spot)	-1.7%	-1.6%	-1.0%
Natural gas use for electricity generation	-3.4%	-2.5%	-1.9%
4.5% HRI at $100/kW			
Retail electricity prices	-0.2%	0.0%	0.0%
Average price of coal delivered to the power sector	0.5%	0.3%	-0.1%
Coal production for power sector use	4.5%	7.1%	7.4%
Price of natural gas delivered to power sector	-1.3%	-1.1%	-0.7%
Price of average Henry Hub (spot)	-1.6%	-1.6%	-1.0%
Natural gas use for electricity generation	-3.4%	-2.3%	-1.6%

The projected energy market and electricity retail rate impacts of this proposal 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 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 proposed rule 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, 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.[1] In September 2017, the SAB issued its final

[1] Science Advisory Board, USEPA. Economy-wide Modeling of the Benefits and Costs of Environmental

report, which provided recommendations on how 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, 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 proposed 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 proposed 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

Regulation.

[2] Science Advisory Board, USEPA. 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. 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 emissions permits); benefits associated with pollution reduction; and transition costs (e.g., from changes in employment or capital mix). EPA did not conduct a quantitative assessment of these distributional impacts for this proposal, 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 proposed 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.[4] The literature evaluating the distributional effects of introducing a new regulation can shed light into the potential distributional impacts of this proposed action; as the literature relates to this action these effects can be interpreted in reverse, in so much as it reduces the burden on regulated entities. 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).

[4] For simplicity of exposition, this discussion focuses on the incidence of compliance costs. If a deregulatory action reduces expected compliance costs then the distribution of cost savings would follow the incidence of the initial compliance costs.

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. 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[5] (Fullerton et al., 2011; Blonz et al., 2012). 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). Depending on the design of the policy, conclusions regarding the overall distributional impact can also depend on how the value of allowances are distributed or any revenue raised from a carbon policy is used (e.g., lowering other taxes) (Burtraw, et al., 2009). There may also be significant heterogeneity in the costs borne by individuals within income deciles (Rausch et al., 2011; Cronin et al., 2017). 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 2017; Hassett et al. 2009).

Given the complexity of problem, understanding the full distributional impacts of compliance costs requires an economy-wide analysis (Rausch and Mowers, 2014). While such an analysis was not conducted for this proposal, 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

[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).

relatively inelastic and, in cost-of-service regions, increased production costs may be passed through electricity prices (e.g. 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.[6] 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, will in and of itself, affect the distribution of regulatory burden.

Examination of the distributional consequences of this action are further complicated by uncertainty regarding the compliance options that might have ultimately been adopted under the CPP absent of this proposed action. For example, in cases where mass-based trading programs were adopted, the distributional impacts would also depend on how allowances would have been distributed. 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

This proposed rule would affect the level and distribution of air pollutants in the atmosphere. A distributional, or Environmental Justice, analysis characterizes the change in air pollution exposure and risk among population subgroups (see U.S. EPA 2016). Often the baseline incidence of health outcomes is greater among low-income or minority population subgroups 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

[6] The directional results previously discussed are prior to any recycling of revenue from emissions fees or auctioned permits.

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. While the Agency did not perform a quantitative distributional analysis for this proposed policy, the Agency anticipates doing so in the Regulatory Impact Analysis for the final promulgated policy.

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 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.[7] In this section we discuss the potential employment impacts of this proposed rule.

[7] 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.

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 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.[8] 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.

[8] 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.

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 this regulatory proposal, EPA expects potential for changes in the amount of labor needed in different parts of the utility power sector.[9] These employment impacts, both negative and positive, are likely to be smaller in magnitude than those described in the 2015 CPP RIA (U.S. EPA 2015a), given the difference between total costs in the proposed option of this rule as compared to the 2015 CPP.

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 of new EGUs, generation shifts, and changes in fuel use and type. Considering first the electric power sector, transitional employment impacts may occur in the short-run, where we project a decrease 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 the proposed rule 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 heat rate improvement is maintained in future years. (Staudt 2014). Likewise, there are similar categories of employment for the other shifts caused by the proposed rule such as a decrease 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.

[9] 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).

Given the range of approaches to heat rate improvements that may be used to meet the requirements of the proposed rule, and the flexibility for States to determine these requirements, it is challenging to quantify the associated employment impacts. For this regulatory proposal, based on the illustrative scenarios modeled in IPM which are described in more detail in chapter 3 of this RIA, EPA expects there may be potential for changes in the amount of labor needed in different parts of the utility power sector, but overall employment impacts are expected to be relatively small. The pattern of how these impacts may be distributed, across projected changes in electricity generation, by fuel type, indicates that coal-fired power sector employment and coal mining employment may be unaffected or positively impacted by this rule, whereas natural gas generation and fuels, nuclear, and renewable generation employment may be unaffected or negatively impacted by the rule.

The U.S. Department of Energy, in cooperation with BLS, gathered and published detailed information on energy employment (U.S. DOE (2017a & 2017b)).[10] Detailed information on characteristics of workers, by job tasks, is available for the electricity sector and related sectors, and by state. To shed light on who will be affected by any potential employment changes associated with the proposed rule, 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

[10] 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/.

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 and 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 proposed 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 this proposed rule; for example, if their skill set qualified them for new jobs implementing heat rate improvements.

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 this action, relative to the base case, which includes the CPP. We evaluate the potential regulatory impacts of the illustrative No CPP scenario and the three illustrative policy scenarios 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 beginning-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 proposed 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 avoided compliance costs reported in this RIA are not social costs, although elements of the compliance costs are 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.

6.2 Methods

EPA calculated the present value of costs, as well as the benefits and net benefits, for the years 2023 through 2037, using both a three percent and seven percent beginning-of-period discount rate from the perspective of 2016. This calculation of a present value requires an annual stream of costs for each year of the 2023-2037 timeframe. 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 proposed 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] EPA has estimated MR&R costs for 2023, and applies these costs only to 2023 in the present value analysis. MR&R costs for 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.

EPA calculated the present value and equivalent annualized value of costs, benefits, and net benefits over the 2023-2037 timeframe for the four illustrative scenarios under different methodologies for calculating benefits. In this chapter, negative cost values indicate cost savings,

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[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.

negative benefit values indicate forgone benefits, and negative net benefits indicate forgone net benefits.

6.3 Results

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

This proposed action, when finalized, would be considered a deregulatory action under E.O. 13771, Reducing Regulation and Controlling Regulatory Costs. Three out of the four illustrative scenarios analyzed have total costs less than zero. An E.O. 13771 deregulatory action qualifies as both: (1) one of the actions used to satisfy the provision to repeal or revise at least two existing regulations for each regulation issued, and (2) a cost savings for purposes of the total incremental cost allowance.

Table 6-1 presents the undiscounted compliance costs for the four illustrative scenarios, relative to the base case, which includes the CPP. 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 Scenarios, Relative to Base Case (CPP), 2023-2037 (billion 2016$)

	No CPP	2% HRI at $50/kW	4.5% HRI at $50/kW	4.5% HRI at $100/kW
2023	(0.1)	(0.0)	(0.0)	(0.0)
2024	(0.0)	0.0	0.0	0.0
2025	(0.7)	0.0	(0.6)	0.5
2026	(0.7)	0.0	(0.6)	0.5
2027	(0.7)	0.0	(0.6)	0.5
2028	(0.7)	(0.2)	(1.0)	0.2
2029	(0.7)	(0.2)	(1.0)	0.2
2030	(0.7)	(0.2)	(1.0)	0.2
2031	(0.7)	(0.2)	(1.0)	0.2
2032	(0.7)	(0.2)	(1.0)	0.2
2033	(0.4)	0.1	(0.6)	0.5
2034	(0.4)	0.1	(0.6)	0.5
2035	(0.4)	0.1	(0.6)	0.5
2036	(0.4)	0.1	(0.6)	0.5
2037	(0.4)	0.1	(0.6)	0.5

[a] All estimates are rounded to one decimal point, so figures may not sum due to independent rounding.
[b] Compliance costs included avoided compliance costs and avoided MR&R costs.
[c] Negative costs indicate avoided costs.

EPA calculated the present value of costs using both a three percent and seven percent discount rate. Whereas beginning-of-period discount rates are used elsewhere in the RIA, EPA used an end-of-period discount rate for E.O. 13771 analysis. These estimates for the four illustrative scenarios are presented in Table 6-2 and are from the perspective of 2016.

Table 6-2 shows that that three out of the four illustrative scenarios provide cost savings. Under the illustrative No CPP scenario, the present value of the stream of cost savings is $5.0 billion when discounted at 3 percent, and $2.9 billion when discounted at 7 percent. Under the illustrative 2 percent HRI at $50/kW scenario, the present value of the stream of cost savings is $0.4 billion when discounted at 3 percent, and $0.2 billion when discounted at 7 percent. Under the illustrative 4.5 percent HRI at $50/kW scenario, the present value of the stream of cost savings is $6.2 billion when discounted at 3 percent, and $3.5 billion when discounted at 7 percent. Under the illustrative 4.5 percent HRI at $100/kW scenario, the present value of the stream of costs is $2.9 billion when discounted at 3 percent, and $1.6 billion when discounted at 7 percent. These avoided compliance cost estimates represent the regulatory cost savings related to the regulatory allowance under E.O. 13771. Table 6-2 also presents the equivalent annualized value, which is a calculation that yields and even-flow of figures that would yield an equivalent present value.

Table 6-2 Present Value of Compliance Costs for the Illustrative Scenario, Relative to Base Case (CPP), 3 and 7 Percent Discount Rates, 2023-2037 (billion 2016$)

	No CPP		2% HRI at $50/kW		4.5% HRI at $50/kW		4.5% HRI at $100/kW	
	3%	**7%**	**3%**	**7%**	**3%**	**7%**	**3%**	**7%**
2023	(0.1)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
2024	(0.0)	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0
2025	(0.5)	(0.4)	0.0	0.0	(0.5)	(0.3)	0.4	0.3
2026	(0.5)	(0.3)	0.0	0.0	(0.5)	(0.3)	0.4	0.2
2027	(0.5)	(0.3)	0.0	0.0	(0.5)	(0.3)	0.4	0.2
2028	(0.5)	(0.3)	(0.2)	(0.1)	(0.7)	(0.4)	0.1	0.1
2029	(0.5)	(0.3)	(0.2)	(0.1)	(0.6)	(0.4)	0.1	0.1
2030	(0.5)	(0.3)	(0.1)	(0.1)	(0.6)	(0.3)	0.1	0.1
2031	(0.4)	(0.2)	(0.1)	(0.1)	(0.6)	(0.3)	0.1	0.1
2032	(0.4)	(0.2)	(0.1)	(0.1)	(0.6)	(0.3)	0.1	0.1
2033	(0.2)	(0.1)	0.1	0.0	(0.4)	(0.2)	0.3	0.1
2034	(0.2)	(0.1)	0.1	0.0	(0.4)	(0.2)	0.3	0.1
2035	(0.2)	(0.1)	0.1	0.0	(0.3)	(0.2)	0.3	0.1
2036	(0.2)	(0.1)	0.1	0.0	(0.3)	(0.1)	0.2	0.1
2037	(0.2)	(0.1)	0.1	0.0	(0.3)	(0.1)	0.2	0.1
Present Value	**(5.0)**	**(2.9)**	**(0.4)**	**(0.2)**	**(6.2)**	**(3.5)**	**2.9**	**1.6**
Equivalent Annualized Value	**(0.4)**	**(0.3)**	**(0.0)**	**(0.0)**	**(0.5)**	**(0.4)**	**0.2**	**0.2**

Notes: Negative costs indicate avoided costs. Compliance costs included avoided compliance costs and avoided MR&R costs. All estimates are rounded to one decimal point, so figures may not sum due to independent rounding. This table reflects end-of-period discount rates.

6.3.2 Net Benefits Analysis

Net benefits analysis is presented in terms of present value and equivalent annualized value from the perspective of 2016, calculated using both a three percent and seven percent beginning-of-period discount rate. As noted earlier, negative cost values indicate cost savings, negative benefit values indicate forgone benefits, and negative net benefits indicate forgone net benefits.

6.3.2.1 Target Pollutant

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 the 2015 Final CPP rulemaking, EPA did not consider alternative regulatory approaches to jointly control CO_2, SO_2, and NO_X emission from existing power plants. This leaves open the possibility that an option which jointly regulates CO_2, 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.

In Table 6-3 through Table 6-7 we offer one perspective on the costs and benefits of this rule by presenting a comparison of the benefit impact associated with the targeted pollutant – CO_2 – with the compliance cost impact. Excluded from this comparison are the benefit impacts from SO_2 and NO_X emission changes that are projected to accompany the CO_2 changes.[5] Table 6-3 presents results for the illustrative No CPP scenario, Table 6-4 presents results for the illustrative 2 percent HRI at $50/kW scenario, Table 6-5 presents results for the illustrative 4.5 percent at $50/kW scenario, and Table 6-6 presents results for the illustrative 4.5 percent at $100/kW scenario. All values in Table 6-3 through Table 6-7 are present value estimates.

[5] 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 6-3 Present Value of Compliance Costs, Benefits, and Net Benefits Associated with Targeted Pollutant (CO_2), Illustrative No CPP Scenario, Relative to Base Case (CPP), 3 and 7 Percent Discount Rates, 2023-2037 (billion 2016$)

	Costs		Domestic Climate Benefits		Net Benefits associated with the Targeted Pollutant (CO_2)	
	3%	**7%**	**3%**	**7%**	**3%**	**7%**
2023	(0.1)	(0.0)	0.0	0.0	0.1	0.0
2024	(0.0)	(0.0)	0.0	0.0	0.0	0.0
2025	(0.6)	(0.4)	(0.2)	(0.0)	0.3	0.4
2026	(0.5)	(0.4)	(0.2)	(0.0)	0.3	0.3
2027	(0.5)	(0.3)	(0.2)	(0.0)	0.3	0.3
2028	(0.5)	(0.3)	(0.4)	(0.0)	0.1	0.3
2029	(0.5)	(0.3)	(0.4)	(0.0)	0.1	0.3
2030	(0.5)	(0.3)	(0.3)	(0.0)	0.1	0.2
2031	(0.5)	(0.3)	(0.3)	(0.0)	0.1	0.2
2032	(0.4)	(0.2)	(0.3)	(0.0)	0.1	0.2
2033	(0.2)	(0.1)	(0.3)	(0.0)	(0.1)	0.1
2034	(0.2)	(0.1)	(0.3)	(0.0)	(0.1)	0.1
2035	(0.2)	(0.1)	(0.3)	(0.0)	(0.1)	0.1
2036	(0.2)	(0.1)	(0.3)	(0.0)	(0.1)	0.1
2037	(0.2)	(0.1)	(0.3)	(0.0)	(0.1)	0.1

Note: Negative costs indicate avoided costs, negative benefits indicate forgone benefits, and negative net benefits indicate forgone net benefits.

Table 6-4 Present Value of Compliance Costs, Benefits, and Net Benefits Associated with Targeted Pollutant (CO_2), Illustrative 2 Percent HRI at $50/kW Scenario, Relative to Base Case (CPP), 3 and 7 Percent Discount Rates, 2023-2037 (billion 2016$)

	Costs		Domestic Climate Benefits		Net Benefits associated with the Targeted Pollutant (CO_2)	
	3%	**7%**	**3%**	**7%**	**3%**	**7%**
2023	(0.0)	(0.0)	0.0	0.0	0.0	0.0
2024	0.0	0.0	0.0	0.0	(0.0)	(0.0)
2025	0.0	0.0	(0.2)	(0.0)	(0.2)	(0.0)
2026	0.0	0.0	(0.2)	(0.0)	(0.2)	(0.0)
2027	0.0	0.0	(0.2)	(0.0)	(0.2)	(0.0)
2028	(0.2)	(0.1)	(0.3)	(0.0)	(0.1)	0.1
2029	(0.2)	(0.1)	(0.3)	(0.0)	(0.1)	0.1
2030	(0.2)	(0.1)	(0.3)	(0.0)	(0.1)	0.1
2031	(0.1)	(0.1)	(0.3)	(0.0)	(0.1)	0.1
2032	(0.1)	(0.1)	(0.3)	(0.0)	(0.1)	0.1
2033	0.1	0.0	(0.2)	(0.0)	(0.3)	(0.1)
2034	0.1	0.0	(0.2)	(0.0)	(0.3)	(0.1)
2035	0.1	0.0	(0.2)	(0.0)	(0.3)	(0.1)
2036	0.1	0.0	(0.2)	(0.0)	(0.3)	(0.1)
2037	0.1	0.0	(0.2)	(0.0)	(0.3)	(0.1)

Note: Negative costs indicate avoided costs, negative benefits indicate forgone benefits, and negative net benefits indicate forgone net benefits.

Table 6-5 Present Value of Compliance Costs, Benefits, and Net Benefits Associated with Targeted Pollutant (CO_2), Illustrative 4.5 Percent HRI at $50/kW Scenario, Relative to Base Case (CPP), 3 and 7 Percent Discount Rates, 2023-2037 (billion 2016$)

	Costs		Domestic Climate Benefits		Net Benefits associated with the Targeted Pollutant (CO_2)	
	3%	**7%**	**3%**	**7%**	**3%**	**7%**
2023	(0.0)	(0.0)	0.0	0.0	0.0	0.0
2024	0.0	0.0	0.0	0.0	(0.0)	(0.0)
2025	(0.5)	(0.4)	(0.2)	(0.0)	0.3	0.3
2026	(0.5)	(0.3)	(0.2)	(0.0)	0.3	0.3
2027	(0.5)	(0.3)	(0.2)	(0.0)	0.3	0.3
2028	(0.7)	(0.4)	(0.3)	(0.0)	0.4	0.4
2029	(0.7)	(0.4)	(0.3)	(0.0)	0.4	0.4
2030	(0.6)	(0.4)	(0.3)	(0.0)	0.4	0.3
2031	(0.6)	(0.3)	(0.3)	(0.0)	0.3	0.3
2032	(0.6)	(0.3)	(0.3)	(0.0)	0.3	0.3
2033	(0.4)	(0.2)	(0.3)	(0.0)	0.1	0.2
2034	(0.4)	(0.2)	(0.3)	(0.0)	0.1	0.2
2035	(0.4)	(0.2)	(0.3)	(0.0)	0.1	0.1
2036	(0.3)	(0.2)	(0.3)	(0.0)	0.1	0.1
2037	(0.3)	(0.1)	(0.3)	(0.0)	0.1	0.1

Note: Negative costs indicate avoided costs, negative benefits indicate forgone benefits, and negative net benefits indicate forgone net benefits.

Table 6-6 Present Value of Compliance Costs, Benefits, and Net Benefits Associated with Targeted Pollutant (CO_2), Illustrative 4.5 Percent HRI at \$100/kW Scenario, Relative to Base Case (CPP), 3 and 7 Percent Discount Rates, 2023-2037 (billion 2016\$)

	Costs		Domestic Climate Benefits		Net Benefits associated with the Targeted Pollutant (CO_2)	
	3%	**7%**	**3%**	**7%**	**3%**	**7%**
2023	(0.0)	(0.0)	0.0	0.0	0.0	0.0
2024	0.0	0.0	0.0	0.0	(0.0)	(0.0)
2025	0.4	0.3	(0.1)	(0.0)	(0.5)	(0.3)
2026	0.4	0.3	(0.1)	(0.0)	(0.5)	(0.3)
2027	0.4	0.2	(0.1)	(0.0)	(0.5)	(0.3)
2028	0.1	0.1	(0.2)	(0.0)	(0.4)	(0.1)
2029	0.1	0.1	(0.2)	(0.0)	(0.3)	(0.1)
2030	0.1	0.1	(0.2)	(0.0)	(0.3)	(0.1)
2031	0.1	0.1	(0.2)	(0.0)	(0.3)	(0.1)
2032	0.1	0.1	(0.2)	(0.0)	(0.3)	(0.1)
2033	0.3	0.1	(0.2)	(0.0)	(0.5)	(0.2)
2034	0.3	0.1	(0.2)	(0.0)	(0.5)	(0.2)
2035	0.3	0.1	(0.2)	(0.0)	(0.5)	(0.1)
2036	0.3	0.1	(0.2)	(0.0)	(0.4)	(0.1)
2037	0.2	0.1	(0.2)	(0.0)	(0.4)	(0.1)

Note: Negative costs indicate avoided costs, negative benefits indicate forgone benefits, and negative net benefits indicate forgone net benefits.

Table 6-7 presents a summary of the present value and equivalent annualized value of cost, benefits, and net benefits associated with the four illustrative scenarios, relative to the base case including CPP.

Table 6-7 Present Value of Compliance Costs, Benefits, and Net Benefits Associated with Targeted Pollutant (CO_2), Relative to Base Case (CPP), 3 and 7 Percent Discount Rates, 2023-2037 (billion 2016$)

	Costs		Domestic Climate Benefits		Net Benefits associated with the Targeted Pollutant (CO_2)	
	3%	**7%**	**3%**	**7%**	**3%**	**7%**
Present Value						
No CPP	(5.2)	(3.1)	(3.9)	(0.4)	1.2	2.7
2% HRI at $50/kW	(0.4)	(0.3)	(3.2)	(0.3)	(2.8)	(0.1)
4.5% HRI at $50/kW	(6.4)	(3.7)	(3.2)	(0.3)	3.2	3.4
4.5% HRI at $100/kW	3.0	1.7	(2.4)	(0.2)	(5.4)	(2.0)
Equivalent Annualized Value						
No CPP	(0.4)	(0.3)	(0.3)	(0.0)	0.1	0.3
2% HRI at $50/kW	(0.0)	(0.0)	(0.3)	(0.0)	(0.2)	(0.0)
4.5% HRI at $50/kW	(0.5)	(0.4)	(0.3)	(0.0)	0.3	0.4
4.5% HRI at $100/kW	0.3	0.2	(0.2)	(0.0)	(0.5)	(0.2)

Note: Negative costs indicate avoided costs, negative benefits indicate forgone benefits, and negative net benefits indicate forgone net benefits.

6.3.2.2 Net Benefits Including Forgone 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 scenarios, inclusive of the benefit impacts from the 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.

There are additional important benefit impacts that EPA could not monetize. Due to current data and modeling limitations, our estimates of the benefit impacts from changing 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 changing emissions of non-CO_2 greenhouse gases and co-benefits from changes in exposure to SO_2, NO_X, and hazardous air pollutants (e.g., mercury), as well as ecosystem effects and visibility impairment.

Table 6-8 through Table 6-12 contain present value estimates of compliance costs, benefits, and net benefits inclusive of ancillary health co-benefits for the four illustrative scenarios.

Table 6-8 Illustrative No CPP Scenario: Present Value of Compliance Costs, Benefits (Inclusive of Health Co-Benefits), and Net Benefits, Relative to Base Case (CPP), 20230-2037 (billion 2016$)

	Costs		Benefits						Net Benefits					
	3%	7%	3%			7%			3%			7%		
2023	(0.1)	(0.0)	0.0	to	0.0	0.0	to	0.0	0.1	to	0.1	0.0	to	0.0
2024	(0.0)	(0.0)	0.0	to	0.0	0.0	to	0.0	0.0	to	0.0	0.0	to	0.0
2025	(0.6)	(0.4)	(2.4)	to	(5.3)	(1.4)	to	(3.3)	(1.9)	to	(4.8)	(1.1)	to	(2.9)
2026	(0.5)	(0.4)	(2.4)	to	(5.3)	(1.4)	to	(3.2)	(1.9)	to	(4.8)	(1.0)	to	(2.8)
2027	(0.5)	(0.3)	(2.4)	to	(5.2)	(1.3)	to	(3.1)	(1.9)	to	(4.7)	(1.0)	to	(2.7)
2028	(0.5)	(0.3)	(3.6)	to	(7.9)	(1.9)	to	(4.4)	(3.1)	to	(7.3)	(1.6)	to	(4.1)
2029	(0.5)	(0.3)	(3.6)	to	(7.8)	(1.8)	to	(4.2)	(3.1)	to	(7.3)	(1.5)	to	(3.9)
2030	(0.5)	(0.3)	(3.6)	to	(7.9)	(1.8)	to	(4.1)	(3.1)	to	(7.4)	(1.5)	to	(3.8)
2031	(0.5)	(0.3)	(3.5)	to	(7.8)	(1.7)	to	(3.9)	(3.1)	to	(7.3)	(1.4)	to	(3.6)
2032	(0.4)	(0.2)	(3.5)	to	(7.8)	(1.6)	to	(3.8)	(3.1)	to	(7.3)	(1.4)	to	(3.5)
2033	(0.2)	(0.1)	(2.5)	to	(5.4)	(1.1)	to	(2.5)	(2.3)	to	(5.2)	(1.0)	to	(2.4)
2034	(0.2)	(0.1)	(2.5)	to	(5.4)	(1.0)	to	(2.4)	(2.2)	to	(5.1)	(0.9)	to	(2.3)
2035	(0.2)	(0.1)	(2.4)	to	(5.3)	(1.0)	to	(2.3)	(2.2)	to	(5.1)	(0.9)	to	(2.2)
2036	(0.2)	(0.1)	(2.4)	to	(5.3)	(0.9)	to	(2.2)	(2.2)	to	(5.0)	(0.8)	to	(2.1)
2037	(0.2)	(0.1)	(2.4)	to	(5.2)	(0.9)	to	(2.1)	(2.2)	to	(5.0)	(0.8)	to	(2.0)

Note: Negative costs indicate avoided costs, negative benefits indicate forgone benefits, and negative net benefits indicate forgone net benefits.

Table 6-9 Illustrative 2 Percent HRI at $50/kW Scenario: Present Value of Compliance Costs, Benefits (Inclusive of Health Co-Benefits), and Net Benefits, Relative to Base Case (CPP), 2023-2037 (billion 2016$)

	Costs		Benefits						Net Benefits					
	3%	7%	3%			7%			3%			7%		
2023	(0.0)	(0.0)	0.0	to	0.0	0.0	to	0.0	0.0	to	0.0	0.0	to	0.0
2024	0.0	0.0	0.0	to	0.0	0.0	to	0.0	(0.0)	to	(0.0)	(0.0)	to	(0.0)
2025	0.0	0.0	(2.2)	to	(4.7)	(1.3)	to	(3.0)	(2.2)	to	(4.7)	(1.3)	to	(3.0)
2026	0.0	0.0	(2.1)	to	(4.7)	(1.2)	to	(2.8)	(2.2)	to	(4.7)	(1.3)	to	(2.9)
2027	0.0	0.0	(2.1)	to	(4.6)	(1.2)	to	(2.7)	(2.1)	to	(4.7)	(1.2)	to	(2.7)
2028	(0.2)	(0.1)	(3.2)	to	(7.0)	(1.7)	to	(3.9)	(3.0)	to	(6.8)	(1.6)	to	(3.8)
2029	(0.2)	(0.1)	(3.2)	to	(6.9)	(1.6)	to	(3.7)	(3.0)	to	(6.8)	(1.5)	to	(3.6)
2030	(0.2)	(0.1)	(3.2)	to	(7.3)	(1.6)	to	(3.8)	(3.1)	to	(7.2)	(1.5)	to	(3.7)
2031	(0.1)	(0.1)	(3.2)	to	(7.2)	(1.5)	to	(3.7)	(3.0)	to	(7.1)	(1.5)	to	(3.6)
2032	(0.1)	(0.1)	(3.2)	to	(7.2)	(1.5)	to	(3.5)	(3.1)	to	(7.1)	(1.4)	to	(3.4)
2033	0.1	0.0	(2.3)	to	(5.0)	(1.0)	to	(2.3)	(2.3)	to	(5.1)	(1.0)	to	(2.4)
2034	0.1	0.0	(2.2)	to	(5.0)	(0.9)	to	(2.2)	(2.3)	to	(5.1)	(1.0)	to	(2.3)
2035	0.1	0.0	(1.9)	to	(4.2)	(0.8)	to	(1.8)	(2.0)	to	(4.3)	(0.8)	to	(1.8)
2036	0.1	0.0	(1.9)	to	(4.2)	(0.7)	to	(1.7)	(2.0)	to	(4.3)	(0.8)	to	(1.8)
2037	0.1	0.0	(1.9)	to	(4.1)	(0.7)	to	(1.6)	(2.0)	to	(4.2)	(0.7)	to	(1.7)

Note: Negative costs indicate avoided costs, negative benefits indicate forgone benefits, and negative net benefits indicate forgone net benefits.

Table 6-10 Illustrative 4.5 Percent HRI at $50/kW Scenario: Present Value of Compliance Costs, Benefits (Inclusive of Health Co-Benefits), and Net Benefits, Relative to Base Case (CPP), 2023-2037 (billion 2016$)

	Costs		Benefits						Net Benefits					
	3%	7%	3%			7%			3%			7%		
2023	(0.0)	(0.0)	0.0	to	0.0	0.0	to	0.0	0.0	to	0.0	0.0	to	0.0
2024	0.0	0.0	0.0	to	0.0	0.0	to	0.0	(0.0)	to	(0.0)	(0.0)	to	(0.0)
2025	(0.5)	(0.4)	(2.2)	to	(4.9)	(1.4)	to	(3.1)	(1.7)	to	(4.4)	(1.0)	to	(2.8)
2026	(0.5)	(0.3)	(2.2)	to	(4.9)	(1.3)	to	(3.3)	(1.7)	to	(4.4)	(1.0)	to	(2.9)
2027	(0.5)	(0.3)	(2.2)	to	(4.9)	(1.2)	to	(3.1)	(1.7)	to	(4.4)	(0.9)	to	(2.8)
2028	(0.7)	(0.4)	(3.4)	to	(7.3)	(1.8)	to	(4.5)	(2.7)	to	(6.6)	(1.4)	to	(4.1)
2029	(0.7)	(0.4)	(3.3)	to	(7.3)	(1.7)	to	(4.3)	(2.7)	to	(6.6)	(1.3)	to	(3.9)
2030	(0.6)	(0.4)	(3.1)	to	(6.7)	(1.5)	to	(3.5)	(2.4)	to	(6.1)	(1.2)	to	(3.1)
2031	(0.6)	(0.3)	(3.0)	to	(6.7)	(1.5)	to	(3.3)	(2.4)	to	(6.1)	(1.1)	to	(3.0)
2032	(0.6)	(0.3)	(3.0)	to	(6.7)	(1.4)	to	(3.2)	(2.4)	to	(6.1)	(1.1)	to	(2.9)
2033	(0.4)	(0.2)	(2.2)	to	(4.7)	(0.9)	to	(2.1)	(1.8)	to	(4.3)	(0.7)	to	(1.9)
2034	(0.4)	(0.2)	(2.1)	to	(4.6)	(0.9)	to	(2.0)	(1.8)	to	(4.3)	(0.7)	to	(1.9)
2035	(0.4)	(0.2)	(2.5)	to	(5.6)	(1.0)	to	(2.4)	(2.2)	to	(5.2)	(0.9)	to	(2.2)
2036	(0.3)	(0.2)	(2.5)	to	(5.5)	(1.0)	to	(2.3)	(2.2)	to	(5.2)	(0.8)	to	(2.1)
2037	(0.3)	(0.1)	(2.5)	to	(5.4)	(0.9)	to	(2.2)	(2.1)	to	(5.1)	(0.8)	to	(2.0)

Note: Negative costs indicate avoided costs, negative benefits indicate forgone benefits, and negative net benefits indicate forgone net benefits.

Table 6-11 Illustrative 4.5 Percent HRI at $100/kW Scenario: Present Value of Compliance Costs, Benefits (Inclusive of Health Co-Benefits), and Net Benefits, Relative to Base Case (CPP), 2023-2037 (billion 2016$)

	Costs		Benefits						Net Benefits					
	3%	7%	3%			7%			3%			7%		
2023	(0.0)	(0.0)	0.0	to	0.0	0.0	to	0.0	0.0	to	0.0	0.0	to	0.0
2024	0.0	0.0	0.0	to	0.0	0.0	to	0.0	(0.0)	to	(0.0)	(0.0)	to	(0.0)
2025	0.4	0.3	(1.7)	to	(3.8)	(1.1)	to	(2.4)	(2.1)	to	(4.2)	(1.4)	to	(2.7)
2026	0.4	0.3	(1.9)	to	(4.2)	(1.2)	to	(2.8)	(2.2)	to	(4.6)	(1.5)	to	(3.1)
2027	0.4	0.2	(1.8)	to	(4.2)	(1.2)	to	(2.7)	(2.2)	to	(4.5)	(1.4)	to	(2.9)
2028	0.1	0.1	(2.8)	to	(6.3)	(1.7)	to	(3.9)	(2.9)	to	(6.4)	(1.7)	to	(4.0)
2029	0.1	0.1	(2.8)	to	(6.3)	(1.6)	to	(3.7)	(2.9)	to	(6.4)	(1.7)	to	(3.8)
2030	0.1	0.1	(2.6)	to	(5.7)	(1.3)	to	(3.0)	(2.7)	to	(5.8)	(1.4)	to	(3.0)
2031	0.1	0.1	(2.6)	to	(5.6)	(1.2)	to	(2.8)	(2.7)	to	(5.7)	(1.3)	to	(2.9)
2032	0.1	0.1	(2.5)	to	(5.6)	(1.2)	to	(2.7)	(2.7)	to	(5.7)	(1.2)	to	(2.8)
2033	0.3	0.1	(1.8)	to	(3.9)	(0.8)	to	(1.8)	(2.1)	to	(4.2)	(0.9)	to	(1.9)
2034	0.3	0.1	(1.8)	to	(3.9)	(0.8)	to	(1.7)	(2.1)	to	(4.1)	(0.9)	to	(1.9)
2035	0.3	0.1	(1.7)	to	(3.6)	(0.7)	to	(1.5)	(1.9)	to	(3.9)	(0.8)	to	(1.7)
2036	0.3	0.1	(1.6)	to	(3.6)	(0.6)	to	(1.5)	(1.9)	to	(3.8)	(0.8)	to	(1.6)
2037	0.2	0.1	(1.6)	to	(3.5)	(0.6)	to	(1.4)	(1.9)	to	(3.8)	(0.7)	to	(1.5)

Note: Negative costs indicate avoided costs, negative benefits indicate forgone benefits, and negative net benefits indicate forgone net benefits.

Table 6-12 presents a summary of the present value and equivalent annualized value of these four illustrative scenarios, inclusive of ancillary health co-benefits.

Table 6-12 Present Value of Compliance Costs, Benefits (Inclusive of Health Co-Benefits), and Net Benefits, Relative to Base Case (CPP), 3 and 7 Percent Discount Rates, 2023-2037 (billion 2016$)

	Costs		Benefits		Net Benefits	
	3%	7%	3%	7%	3%	7%
Present Value						
No CPP	(5.2)	(3.1)	(37.2) to (81.5)	(17.9) to (41.3)	(32.0) to (76.3)	(14.8) to (38.2)
2% HRI at $50/kW	(0.4)	(0.3)	(32.7) to (72.4)	(15.9) to (36.9)	(32.3) to (72.0)	(15.7) to (36.7)
4.5% HRI at $50/kW	(6.4)	(3.7)	(34.3) to (75.2)	(16.6) to (39.4)	(27.9) to (68.8)	(12.8) to (35.6)
4.5% HRI at $100/kW	3.0	1.7	(27.2) to (60.2)	(13.9) to (31.9)	(30.2) to (63.2)	(15.6) to (33.7)
Equivalent Annualized Value						
No CPP	(0.4)	(0.3)	(3.1) to (6.8)	(2.0) to (4.5)	(2.7) to (6.4)	(1.6) to (4.2)
2% HRI at $50/kW	(0.0)	(0.0)	(2.7) to (6.1)	(1.7) to (4.1)	(2.7) to (6.0)	(1.7) to (4.0)
4.5% HRI at $50/kW	(0.5)	(0.4)	(2.9) to (6.3)	(1.8) to (4.3)	(2.3) to (5.8)	(1.4) to (3.9)
4.5% HRI at $100/kW	0.3	0.2	(2.3) to (5.0)	(1.5) to (3.5)	(2.5) to (5.3)	(1.7) to (3.7)

Note: Negative costs indicate avoided costs, negative benefits indicate forgone benefits, and negative net benefits indicate forgone net benefits.

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

Table 6-13 through Table 6-15 report the estimated benefits, costs, and net benefits of the illustrative scenarios 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 6-12, we report the net benefits calculated using the sum of the estimated ozone and $PM_{2.5}$-related forgone benefits using a no-threshold concentration-response parameter for $PM_{2.5}$. In Table 6-13, we report the net benefits calculated using the sum of the estimated ozone and $PM_{2.5}$-related forgone 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 6-14, we report the net benefits calculated using the sum of the estimated ozone and $PM_{2.5}$-related forgone benefits assuming that $PM_{2.5}$ related benefits fall to zero below the $PM_{2.5}$ National Ambient Air Quality Standard. Finally, we report the net benefits calculated using the sum of the estimated ozone and $PM_{2.5}$-related forgone benefits using an alternative concentration-response parameter to quantify $PM_{2.5}$-attributable risks at low levels (Table 6-15). These are present value and equivalent annualized value estimates, similar to the presentation of results in Table 6-12.

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 in the preceding section, there are additional important benefit impacts that EPA could not monetize.

Table 6-13 Present Value of Compliance Costs, Benefits, and Net Benefits assuming that $PM_{2.5}$ Related Benefits Fall to Zero Below the Lowest Measured Level of Each Long-Term $PM_{2.5}$ Mortality Study, Relative to Base Case (CPP), 3 and 7 Percent Discount Rates, 2023-2037 (billion 2016$)

	Costs		Benefits Excluding Benefits below LML		Net Benefits Excluding Benefits below LML	
	3%	**7%**	**3%**	**7%**	**3%**	**7%**
Present Value						
No CPP	(5.2)	(3.1)	(32.6) to (27.1)	(15.5) to (12.7)	(27.4) to (21.9)	(12.3) to (9.6)
2% HRI at $50/kW	(0.4)	(0.3)	(28.6) to (24.7)	(13.7) to (11.8)	(28.2) to (24.3)	(13.5) to (11.5)
4.5% HRI at $50/kW	(6.4)	(3.7)	(29.8) to (23.9)	(14.2) to (11.2)	(23.4) to (17.5)	(10.4) to (7.5)
4.5% HRI at $100/kW	3.0	1.7	(23.7) to (19.3)	(11.5) to (9.3)	(26.7) to (22.3)	(13.3) to (11.1)
Equivalent Annualized Value						
No CPP	(0.4)	(0.3)	(2.7) to (2.3)	(1.7) to (1.4)	(2.3) to (1.8)	(1.4) to (1.1)
2% HRI at $50/kW	(0.0)	(0.0)	(2.4) to (2.1)	(1.5) to (1.3)	(2.4) to (2.0)	(1.5) to (1.3)
4.5% HRI at $50/kW	(0.5)	(0.4)	(2.5) to (2.0)	(1.6) to (1.2)	(2.0) to (1.5)	(1.1) to (0.8)
4.5% HRI at $100/kW	0.3	0.2	(2.0) to (1.6)	(1.3) to (1.0)	(2.2) to (1.9)	(1.5) to (1.2)

Note: Negative costs indicate avoided costs, negative benefits indicate forgone benefits, and negative net benefits indicate forgone net benefits.

Table 6-14 Present Value of Compliance Costs, Benefits, and Net Benefits assuming that $PM_{2.5}$ Related Benefits Fall to Zero Below the $PM_{2.5}$ National Ambient Air Quality Standard, Relative to Base Case (CPP), 3 and 7 Percent Discount Rates, 2023-2037 (billion 2016$)

	Costs		Benefits Excluding Benefits below NAAQS		Net Benefits Excluding Benefits below NAAQS	
	3%	**7%**	**3%**	**7%**	**3%**	**7%**
Present Value						
No CPP	(5.2)	(3.1)	(5.6) to (9.8)	(1.3) to (3.7)	(0.4) to (4.6)	1.8 to (0.6)
2% HRI at $50/kW	(0.4)	(0.3)	(5.0) to (9.6)	(1.3) to (3.8)	(4.7) to (9.2)	(1.1) to (3.6)
4.5% HRI at $50/kW	(6.4)	(3.7)	(4.3) to (7.0)	(0.9) to (2.4)	2.1 to (0.6)	2.8 to 1.4
4.5% HRI at $100/kW	3.0	1.7	(3.5) to (6.2)	(0.9) to (2.4)	(6.5) to (9.2)	(2.6) to (4.2)
Equivalent Annualized Value						
No CPP	(0.4)	(0.3)	(0.5) to (0.8)	(0.1) to (0.4)	(0.0) to (0.4)	0.2 to (0.1)
2% HRI at $50/kW	(0.0)	(0.0)	(0.4) to (0.8)	(0.1) to (0.4)	(0.4) to (0.8)	(0.1) to (0.4)
4.5% HRI at $50/kW	(0.5)	(0.4)	(0.4) to (0.6)	(0.1) to (0.3)	0.2 to (0.1)	0.3 to 0.2
4.5% HRI at $100/kW	0.3	0.2	(0.3) to (0.5)	(0.1) to (0.3)	(0.5) to (0.8)	(0.3) to (0.5)

Note: Negative costs indicate avoided costs, negative benefits indicate forgone benefits, and negative net benefits indicate forgone net benefits.

Table 6-15 Present Value of Compliance Costs, Benefits, and Net Benefits assuming Alternate Method for Calculating $PM_{2.5}$ Benefits at Low Levels, Relative to Base Case (CPP), 3 and 7 Percent Discount Rates, 2023-2037 (billion 2016$)

	Costs		Benefits Assuming Alternate Concentration-Response		Net Benefits Assuming Alternate Concentration-Response	
	3%	**7%**	**3%**	**7%**	**3%**	**7%**
Present Value						
No CPP	(5.2)	(3.1)	(67.7)	(33.8)	(62.5)	(30.7)
2% HRI at $50/kW	(0.4)	(0.3)	(59.3)	(29.9)	(58.9)	(29.7)
4.5% HRI at $50/kW	(6.4)	(3.7)	(63.2)	(31.8)	(56.8)	(28.0)
4.5% HRI at $100/kW	3.0	1.7	(50.2)	(25.5)	(53.2)	(27.2)
Equivalent Annualized Value						
No CPP	(0.4)	(0.3)	(5.7)	(3.7)	(5.2)	(3.4)
2% HRI at $50/kW	(0.0)	(0.0)	(5.0)	(3.3)	(4.9)	(3.3)
4.5% HRI at $50/kW	(0.5)	(0.4)	(5.3)	(3.5)	(4.8)	(3.1)
4.5% HRI at $100/kW	0.3	0.2	(4.2)	(2.8)	(4.5)	(3.0)

Note: Negative costs indicate avoided costs, negative benefits indicate forgone benefits, and negative net benefits indicate forgone net benefits.

6.4 References

Tieteneberg, T. 1973. "Specific Taxes and the Control of Pollution: A General Equilibrium Analysis." *The Quarterly Journal of Economics,* 86:503-522.

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 in 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, 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]

[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.

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 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, 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

[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.

all parameters other than those superseded by the harmonized inputs (i.e., equilibrium climate 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.

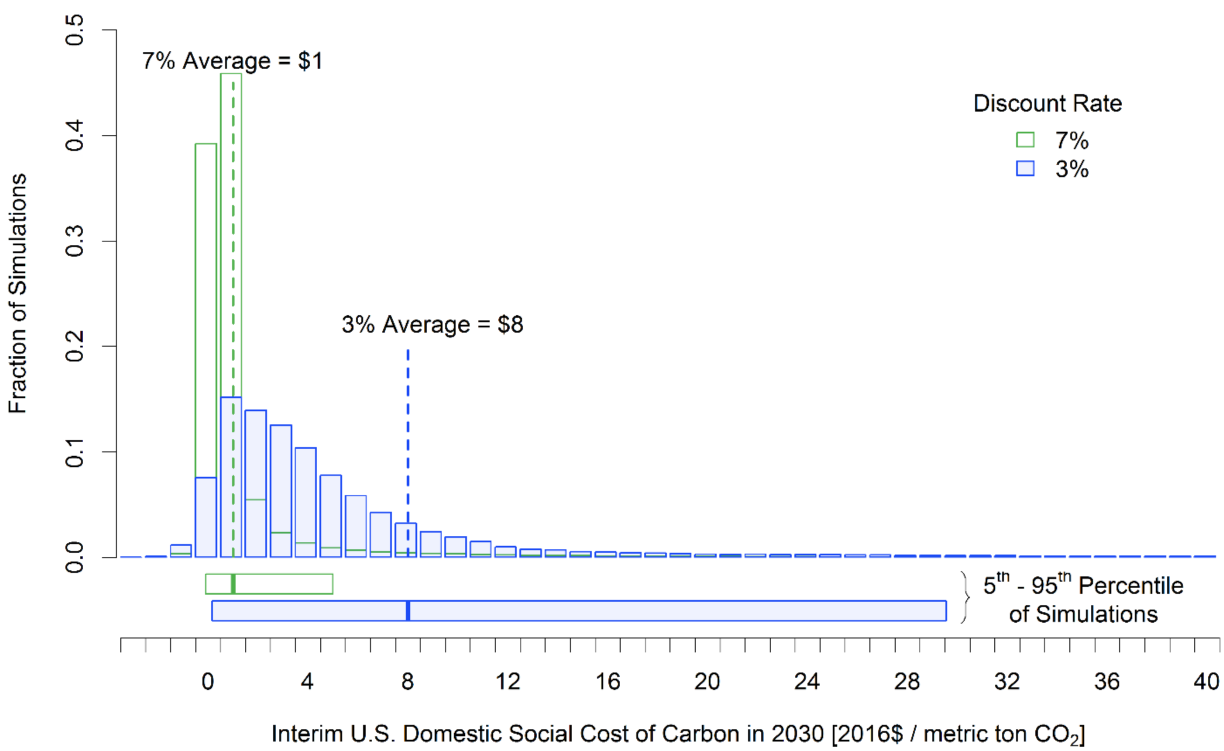

Figure 7-1 Frequency Distribution of Interim Domestic SC-CO2 Estimates for 2030 (in 2016$ per metric ton CO_2)

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

[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).

uncertainty in the discount rate over long time horizons, Circular A-4 suggests “further 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 forgone domestic climate benefits in 2025 are $340, $300, $180 and $460 million under the illustrative 2 percent HRI at $50/kW scenario, 4.5 percent HRI at $50/kW scenario, 4.5 percent HRI at $100/kW scenario, and No CPP scenario, respectively; by 2035, the estimated forgone benefits increase to $590, $640, $470and $710 million under the illustrative 2 percent HRI at $50/kW scenario, 4.5 percent HRI at $50/kW scenario, 4.5 percent HRI at $100/kW scenario, and No CPP scenario, respectively.

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 Forgone 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 forgone 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 forgone CO_2 emission reductions results in estimated forgone global climate benefits in 2025 of \$210, \$180, \$110, and \$280 million (2016\$) under the illustrative 2 percent HRI at \$50/kW scenario, 4.5 percent HRI at \$50/kW scenario, 4.5 percent HRI at \$100/kW scenario, and No CPP scenario, respectively, using a 7 percent discount rate; this increases to \$1.7 billion, \$1.5 billion, \$950 million, and \$2.4 billion (2016\$) under the illustrative 2 percent HRI at \$50/kW scenario, 4.5 percent HRI at \$50/kW scenario, 4.5 percent

[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.

HRI at $100/kW scenario, and No CPP scenario, respectively, using a 3 percent discount rate. By 2035, the forgone global climate benefits are estimated to be $460, $490, $360 and $550 million (2016$) under the illustrative 2 percent HRI at $50/kW scenario, 4.5 percent HRI at $50/kW scenario, 4.5 percent HRI at $100/kW scenario, and No CPP scenario, respectively, using a 7 percent discount rate. Using a 3 percent discount rate, this increases to $3.1, $3.4, $2.5, and $3.8 billion under the illustrative 2 percent HRI at $50/kW scenario, 4.5 percent HRI at $50/kW scenario, 4.5 percent HRI at $100/kW scenario, and No CPP scenario, respectively.

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 forgone global climate benefits in 2025 are $2.6, $2.3, $1.4, and $3.5 billion (2016$) under the illustrative 2 percent HRI at $50/kW scenario, 4.5 percent HRI at $50/kW scenario, 4.5 percent HRI at $100/kW scenario, and No CPP scenario, respectively; by 2035, the forgone global benefits in this sensitivity case increase to $4.5, $4.8, $3.6, and $5.4 billion (2016$) under the illustrative 2 percent HRI at $50/kW scenario, 4.5 percent HRI at $50/kW scenario, 4.5 percent HRI at $100/kW scenario, and No CPP scenario, respectively.

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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 the proposed 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 each of the base case and four illustrative scenarios 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 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.

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).[1] 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

[1] 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 base case 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 2011NEIv2 for point sources, nonpoint sources, commercial marine vessels (CMV), nonroad mobile sources and fires. The onroad mobile source emissions are similar to those in the 2011NEIv2, 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 base case 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[2] 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 speciation profiles for mobile sources and temporal profiles for EGUs.

The projected EGU emissions reflect the emissions reductions in 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. 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).[3] 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 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

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[2] Ancillary data files include temporal, spatial, and VOC/$PM_{2.5}$ speciation surrogates.

[3] 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 EPA directly by power sector sources. They are reported under Part 75 of the CAA.

by EPA in response to the January 2017 NODA, along with 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 observation

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:

$$\mathrm{ME} = \frac{1}{n}\sum_1^n |P - O| \quad \text{(Eq-2)}$$

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:

$$\mathrm{NMB} = \frac{\sum_1^n (P-O)}{\sum_1^n (O)} * 100 \quad \text{(Eq-3)}$$

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:

$$\mathrm{NME} = \frac{\sum_1^n |P-O|}{\sum_1^n (O)} * 100 \quad \text{(Eq-4)}$$

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)[4] and, separately, for monitoring data in the Interagency Monitoring of Protected Visual Environments (IMPROVE)[5] network. For ozone, performance statistics were calculated for modeled concentrations with observed 8-hour daily maximum (MDA8) ozone concentrations at or above 60 ppb[6] over the period May through September for monitoring sites in the Air Quality System (AQS)[7,8] network.

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[4] 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.

[5] 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.

[6] 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.

[7] Additional information on the measurements made at AQS monitoring sites can be found at the following web link: https://www.epa.gov/aqs.

For both $PM_{2.5}$ and ozone, the modeled and predicted pairs of data were aggregated by 9 regions across the U.S. for the calculation of model performance statistics. These 9 regions are shown in Figure 8-2.[9]

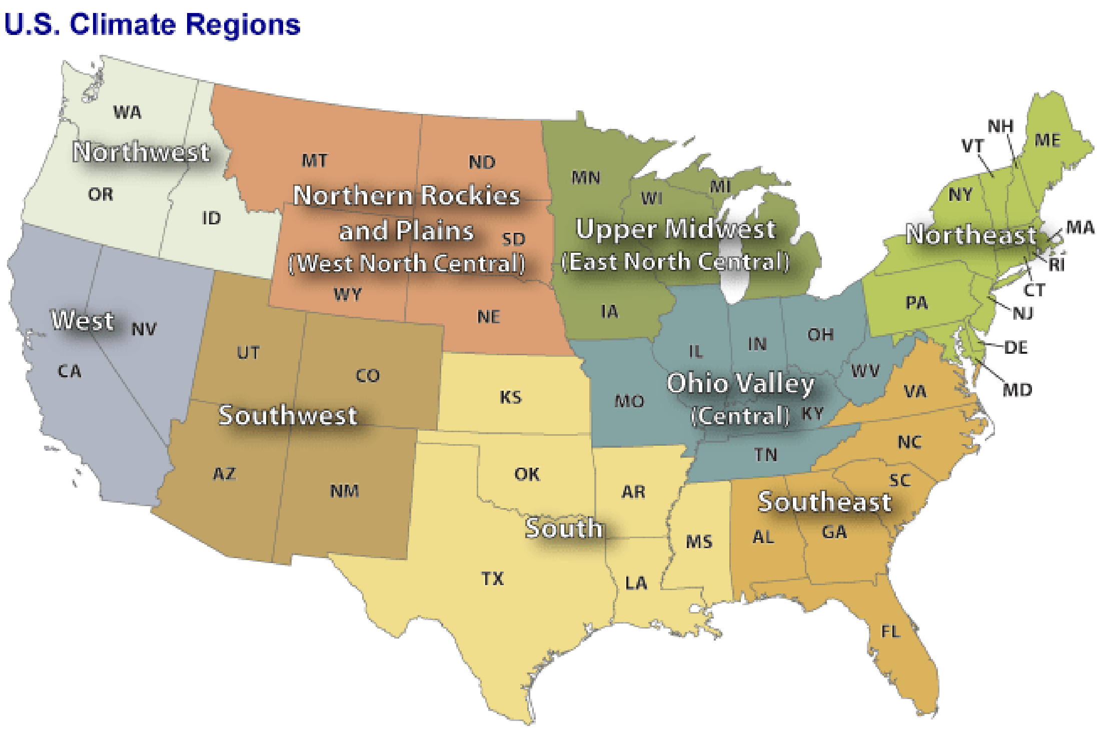

Figure 8-2 NOAA Climate Regions

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).

[8] Note that the AQS data base also includes measurements made at monitoring sites in the Clean Air Status and Trends Network (CASTNet).

[9] 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 modeled and 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

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[10]). 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 9-3 provides a full list of the emissions group tags that were tracked in the source apportionment modeling.

[10] For the purposes of this analysis non-coal fuels include emissions from natural gas, oil, biomass, and waste coal-fired EGUs.

Table 8-3 Table of 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[11]	• 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

[11] 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.

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.

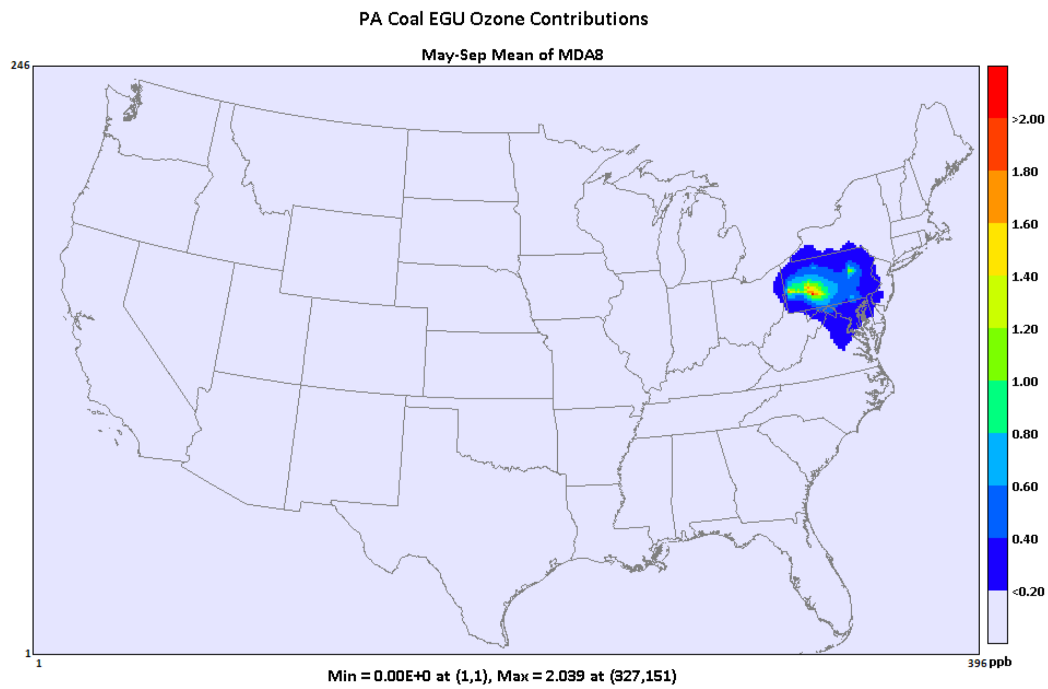

Figure 8-3 Map of Pennsylvania Coal EGU Tag Contribution to Seasonal Average MDA8 Ozone

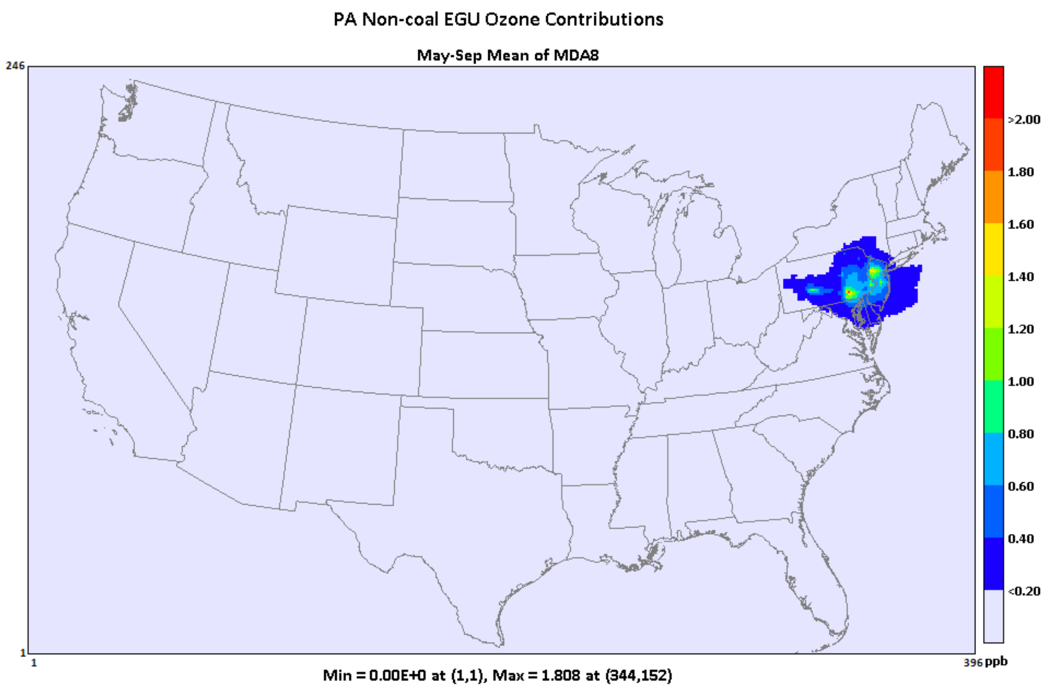

Figure 8-4 Map of Pennsylvania Non-Coal EGU Tag Contribution to Seasonal Average MDA8 Ozone

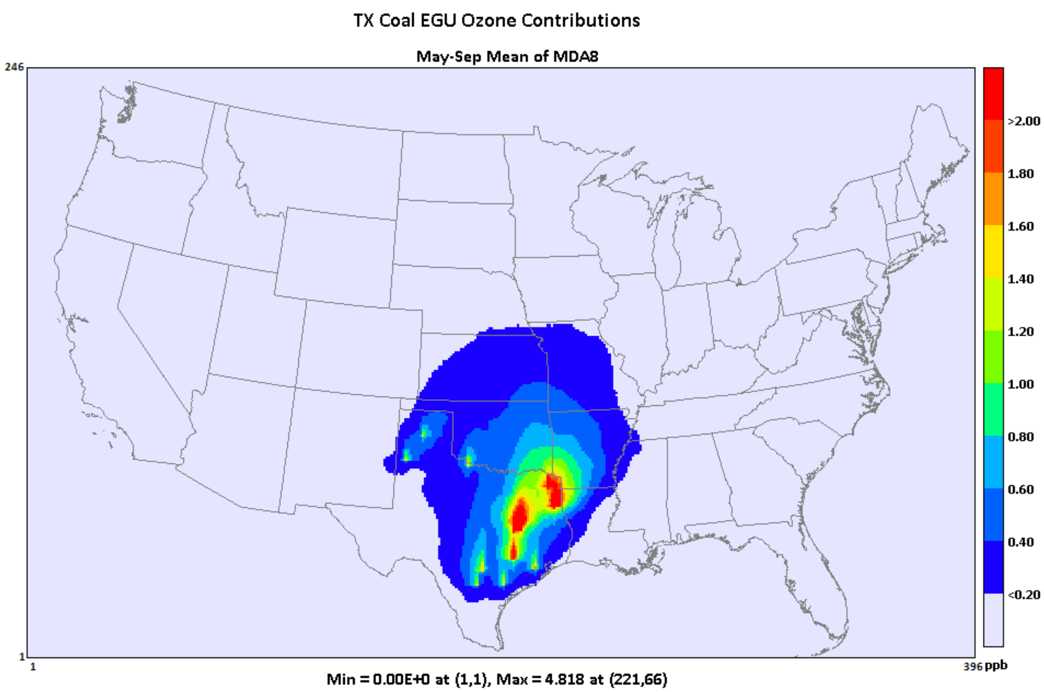

Figure 8-5 Map of Texas Coal EGU Tag Contribution to Seasonal Average MDA8 Ozone

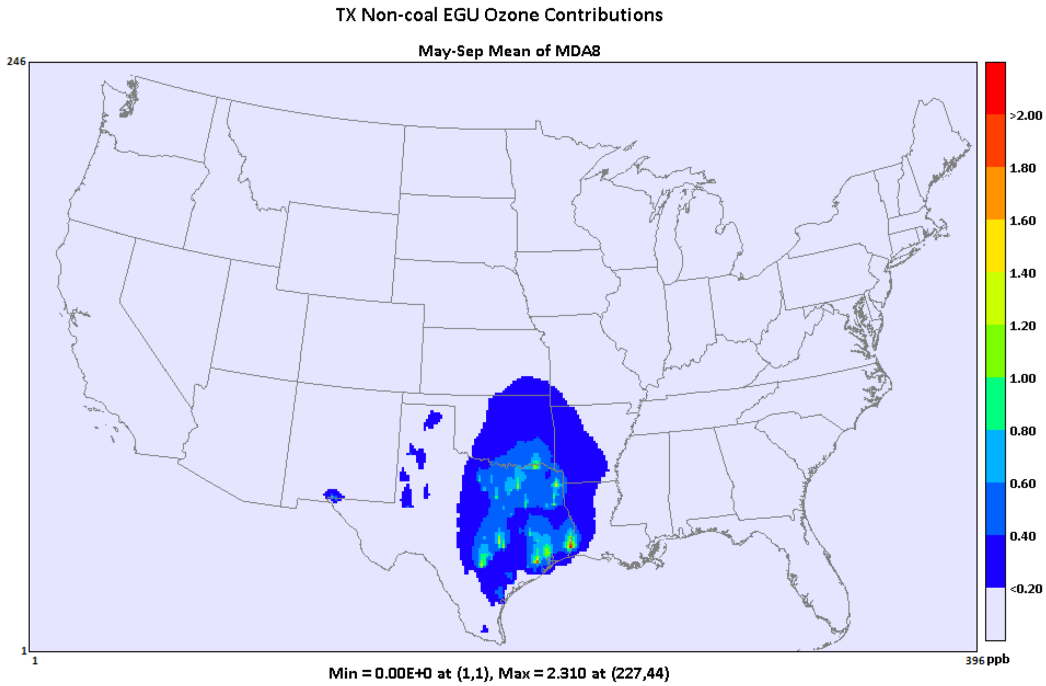

Figure 8-6 Map of Texas Non-Coal EGU Tag Contribution to Seasonal Average MDA8 Ozone

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[12]) 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.

[12] 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.

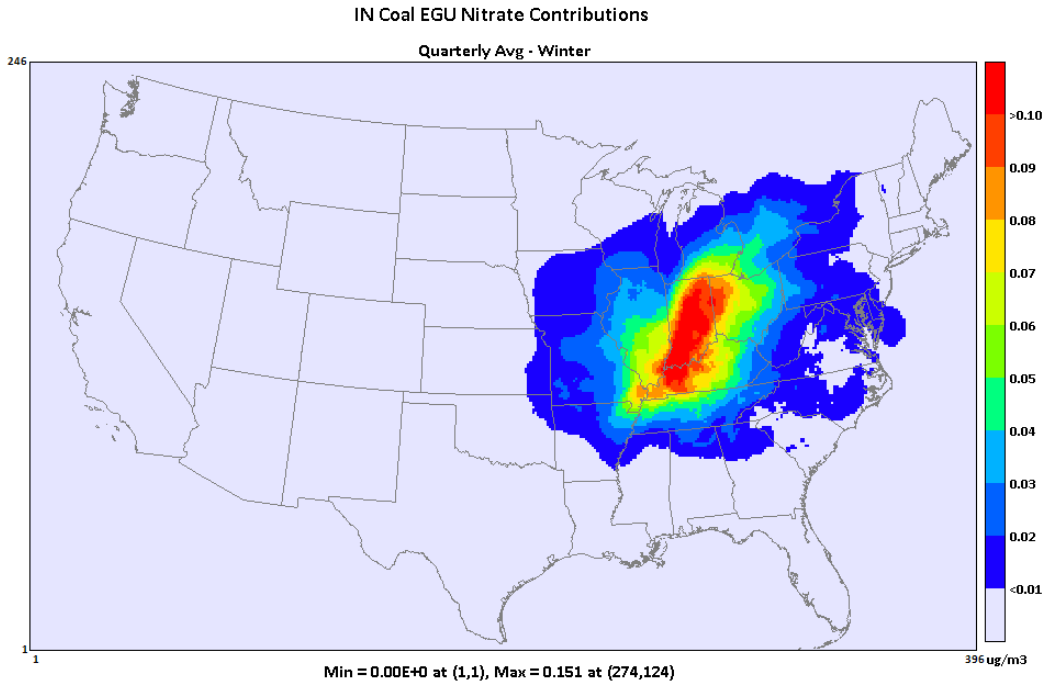

Figure 8-7 Map of Indiana Coal EGU Tag Contributions to Wintertime Average (January-March) Nitrate

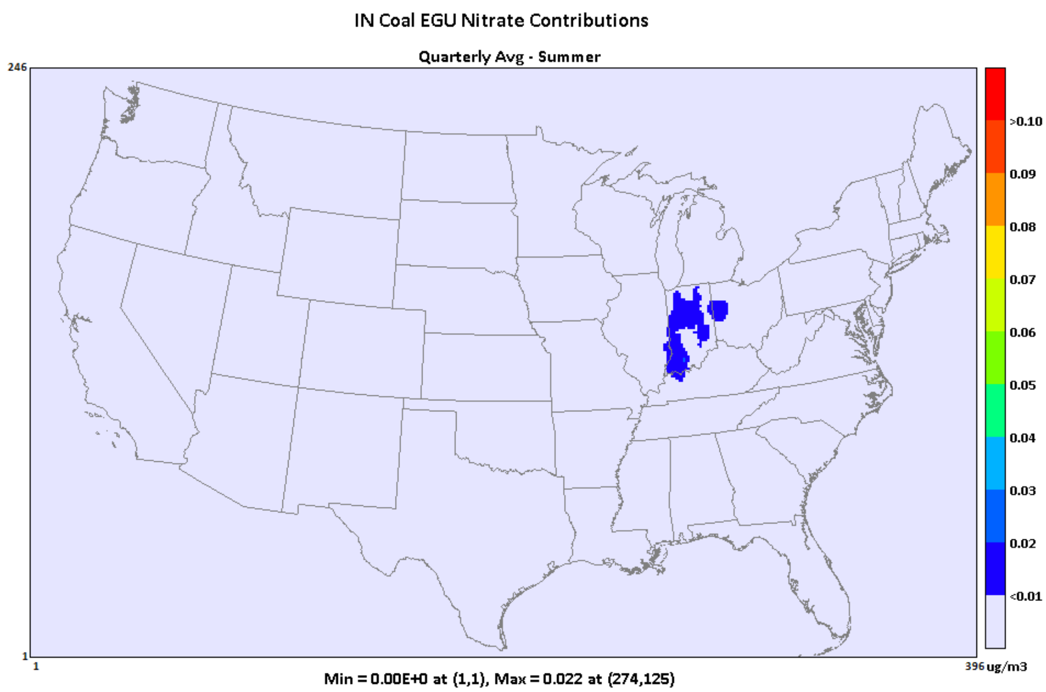

Figure 8-8 Map of Indiana Coal EGU Tag Contributions to Summertime Average (July-September) Nitrate

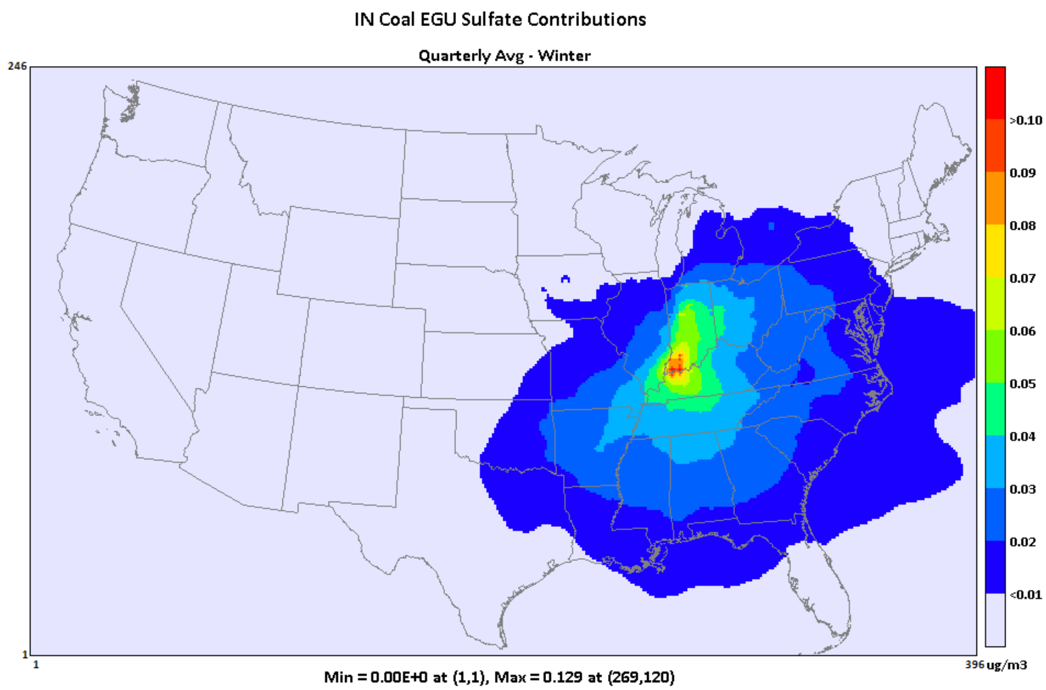

Figure 8-9 Map of Indiana Coal EGU Tag Contributions to Wintertime Average (January-March) Sulfate

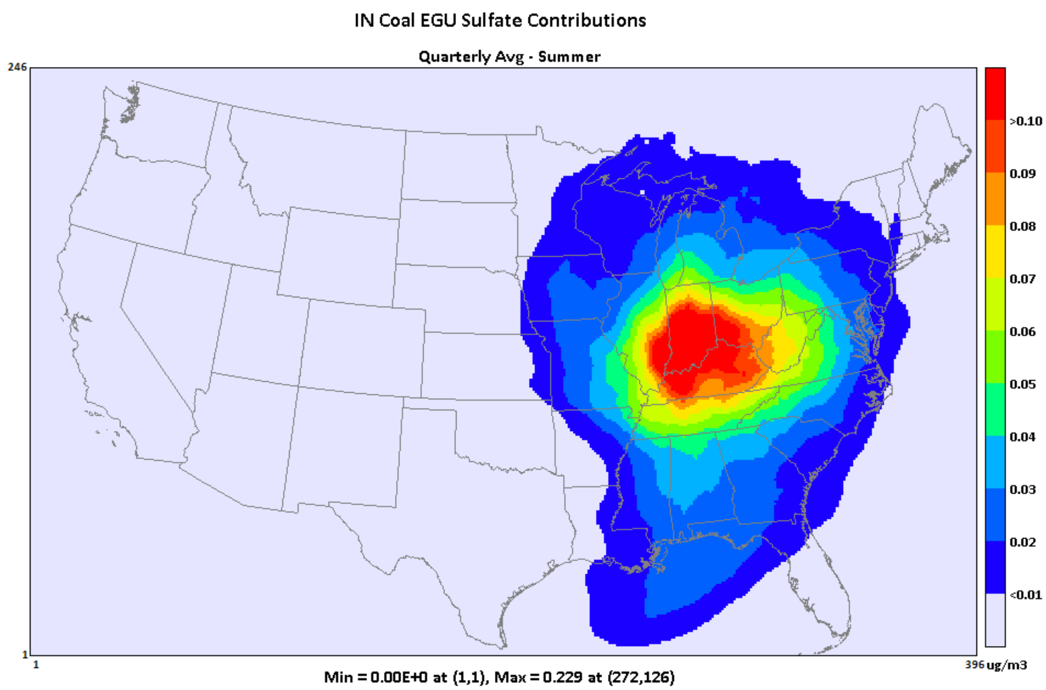

Figure 8-10 Map of Indiana Coal EGU Tag Contributions to Summertime Average (July-September) Sulfate

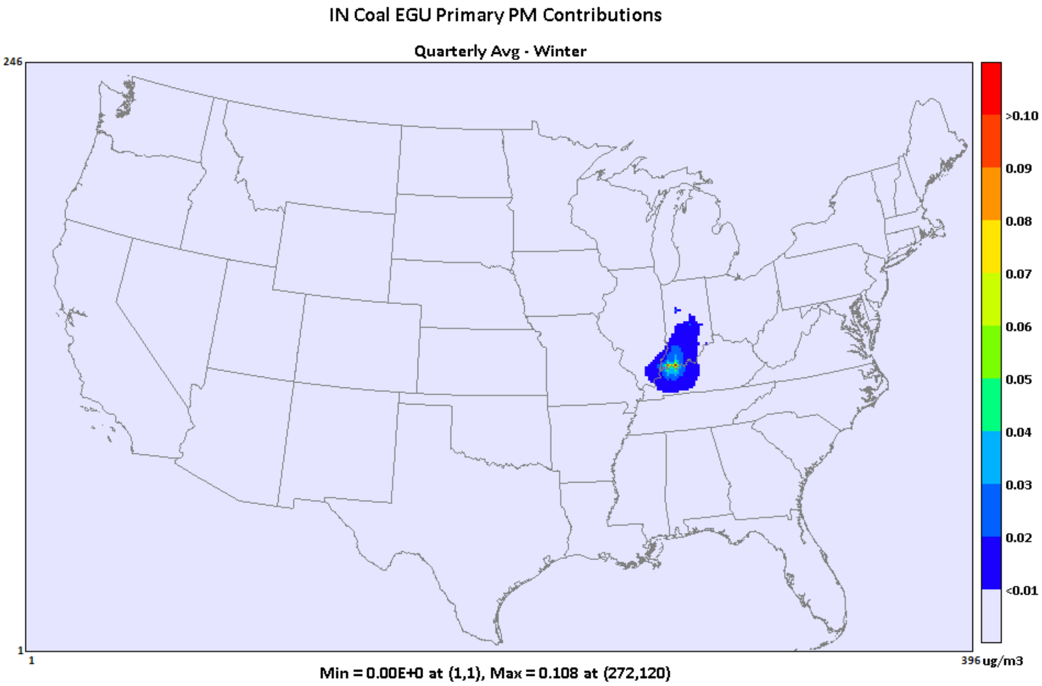

Figure 8-11 Map of Indiana Coal EGU Tag Contributions to Wintertime Average (January-March) Primary $PM_{2.5}$

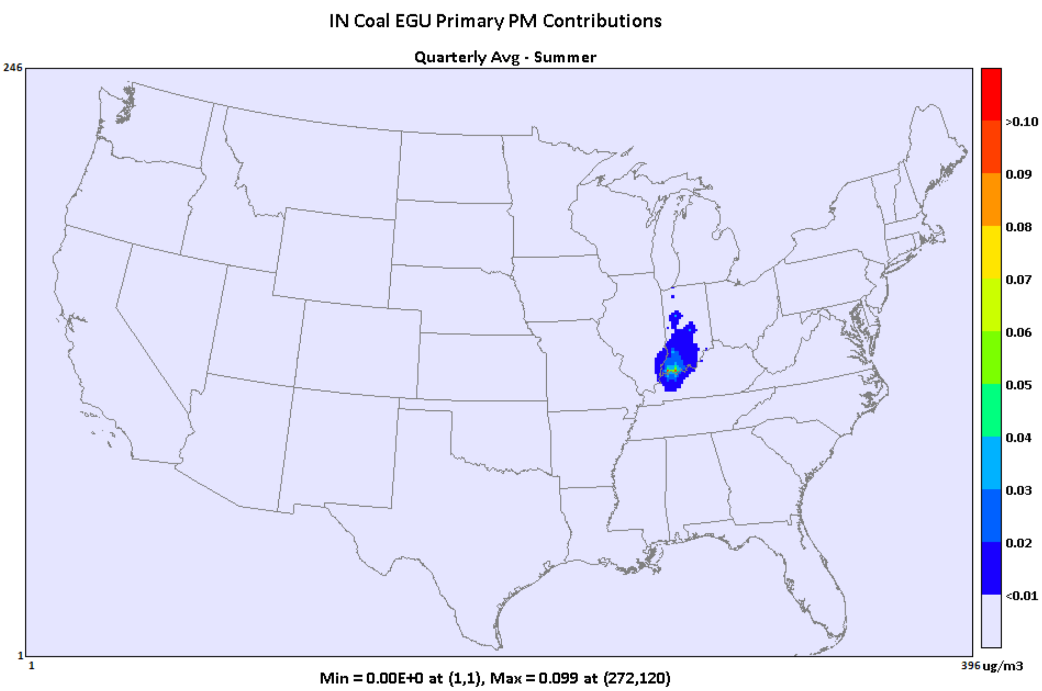

Figure 8-12 Map of Indiana Coal EGU Tag Contributions to Summertime Average (July-September) Primary $PM_{2.5}$

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 Base Case and Four Illustrative Scenarios

As explained in Chapter 4, we created air quality surfaces for the base case and illustrative scenarios 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 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 Base Case and Four Illustrative Scenarios

Annual NO_X, SO_2, and heat input by state and fuel (coal and noncoal) as well as ozone season[13] NO_X by state and fuel were obtained for the base case and illustrative scenarios described in Chapter 3. In addition to NO_X and SO_2, emissions, $PM_{2.5}$ emissions were also needed for the base case and illustrative scenarios. 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[14] 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 was obtained:

[13] For the purpose of this analysis the ozone season is defined as the months of May-September

[14] 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[15] 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

- Base case and illustrative 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 (4) and Equation (5).

$$2023\ Heat\ Scalar_{state,fuel} = \frac{Total\ 2023\ EGU\ CO_{state,fuel}}{2023\ CEMS\ CO_{state,fuel}} \quad \text{(Eq-5)}$$

$$Total\ 2023\ Heat_{state,fuel} = 2023\ Heat\ Scalar_{state,fuel} \times 2023\ CEMS\ Heat_{state,fuel} \quad \text{(Eq-6)}$$

Finally, using Equation (6) and Equation (7), the 2023 $PM_{2.5}$ emissions were scaled to represent $PM_{2.5}$ emissions for the base case and illustrative scenarios based on relative changes in heat input from 2023 (as obtained by Equation 2).

$$PM_{2.5}\ Scalar_{scenario,state,fuel} = \frac{IPM\ Heat_{scenario,state,fuel}}{Total\ 2023\ Heat_{state,fuel}} \quad \text{(Eq-7)}$$

$$PM_{2.5\ scenario,state,fuel} = PM_{2.5}\ Scalar_{scenario,state,fuel} * \ 2023\ EGU\ PM_{2.5\ state,fuel} \quad \text{(Eq-8)}$$

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 base case or illustrative 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 Virginia do the majority of non-coal primary $PM_{2.5}$ emissions come from waste coal. The base

[15] Data obtained from files available at: https://www.cmascenter.org/smoke/documentation/4.5/html/ch02s09s19.html

case and illustrative scenarios 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 base case and illustrative scenarios. 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 base case and illustrative scenarios 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 base case and illustrative scenarios 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 8-6, Table 8-8, Table 8-10, 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 base case and each of the four illustrative scenarios. 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[16] ("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 8-12.[17]

Scaling ratios were applied to create air quality surfaces for ozone using equation (9):

[16] 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.

[17] 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 base case and four illustrative scenarios (~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.

$$Ozone_{m,g,d,i,y} = C_{m,g,d,BC} + C_{m,g,d,int} + C_{m,g,d,bio} + C_{m,g,d,fires} + C_{m,g,d,USanthro} + C_{m,g,d,y,EGUret} + \sum_{t=1}^{T} C_{VOC,m,g,d,t} + \sum_{t=1}^{T} C_{NOx,m,g,d,t} S_{t,i,y} \quad \text{(Eq-9)}$$

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):

$$PM_{s,g,d,i,y} = C_{s,g,d,BC} + C_{s,g,d,int} + C_{s,g,d,bio} + C_{s,g,d,fires} + C_{s,g,d,USanthro} + C_{s,g,d,y,EGUret} + \sum_{t=1}^{T} C_{s,g,d,t} S_{s,t,i,y} \quad \text{(Eq-10)}$$

$$OA_{g,d,i,y} = C_{POA,g,d,BC} + C_{POA,g,d,int} + C_{POA,g,d,bio} + C_{POA,g,d,fires} + C_{POA,g,d,USanthro} + C_{POA,g,d,y,EGUret} + SOA_{g,d} + \sum_{t=1}^{T} C_{POA,g,d,t} S_{pri,t,i,y} \quad \text{(Eq-11)}$$

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 base case and each of the four illustrative scenarios so any uncertainty associated with these assumptions is carried through all 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 base case and illustrative scenarios 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 8-12. For example, in Table 8-7 the scaling ratio for sulfate impacts of coal EGU’s in Louisiana for the 2035 base case 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 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 No CPP case and the 3 illustrative scenarios had scaling ratios ranging from

0.27-0.29 which are relatively close to the base case. 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 base case and illustrative scenarios within a single year.

Table 8-5 Scaling Ratios for Primary $PM_{2.5}$ for Coal EGUs

	Base Case (CPP)			No CPP			2% HRI at $50/kW			4.5% HRI at $50/kW			4.5% HRI at $100/kW		
State	2025	2030	2035	2025	2030	2035	2025	2030	2035	2025	2030	2035	2025	2030	2035
AL	0.58	0.64	0.58	0.47	0.61	0.54	0.47	0.59	0.53	0.53	0.63	0.55	0.50	0.59	0.53
AZ	0.48	0.46	0.40	0.48	0.46	0.40	0.48	0.45	0.39	0.47	0.44	0.38	0.47	0.44	0.38
AR	0.38	0.45	0.38	0.45	0.52	0.51	0.48	0.53	0.51	0.51	0.54	0.53	0.51	0.53	0.52
CA	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
CO	0.88	0.78	0.73	1.10	1.10	1.01	1.08	1.08	0.99	1.06	1.05	0.98	1.06	1.05	0.98
CT+RI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DE+NJ	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FL	0.44	0.42	0.51	0.39	0.40	0.50	0.41	0.41	0.50	0.42	0.43	0.50	0.41	0.43	0.50
GA	0.42	0.49	0.43	0.50	0.51	0.45	0.50	0.51	0.48	0.50	0.51	0.48	0.49	0.51	0.48
IL	0.85	0.82	0.75	0.82	0.81	0.74	0.82	0.80	0.74	0.81	0.79	0.74	0.79	0.76	0.71
IN	0.67	0.68	0.58	0.66	0.67	0.57	0.65	0.66	0.56	0.64	0.65	0.56	0.64	0.65	0.56
IA	0.74	0.70	0.64	0.93	0.89	0.88	0.92	0.88	0.87	0.91	0.88	0.86	0.90	0.87	0.86
KS	0.68	0.59	0.59	0.91	0.86	0.79	0.90	0.87	0.80	0.90	0.86	0.80	0.90	0.86	0.80
KY	0.36	0.34	0.25	0.35	0.31	0.24	0.35	0.31	0.24	0.34	0.32	0.25	0.34	0.31	0.24
LA	0.16	0.19	0.22	0.15	0.19	0.23	0.15	0.16	0.20	0.15	0.21	0.21	0.15	0.19	0.19
ME+MA+NH+VT	0.22	0.22	0.22	0.17	0.17	0.17	0.06	0.06	0.06	0.13	0.13	0.13	0.00	0.00	0.00
MD	0.10	0.00	0.00	0.07	0.00	0.00	0.10	0.01	0.00	0.10	0.05	0.00	0.10	0.05	0.00
MI	0.79	0.73	0.67	0.95	0.96	0.87	0.94	0.95	0.87	0.92	0.93	0.89	0.92	0.92	0.87
MN	1.11	0.91	0.87	1.27	0.96	0.95	1.23	0.95	0.93	1.16	0.97	0.91	1.16	0.97	0.91
MS	0.28	0.30	0.30	0.23	0.27	0.28	0.22	0.27	0.29	0.23	0.30	0.30	0.27	0.30	0.30
MO	0.81	0.77	0.72	0.95	0.93	0.90	0.93	0.90	0.88	0.94	0.91	0.89	0.92	0.89	0.86
MT	0.94	0.94	0.88	1.04	1.04	1.04	1.02	1.02	1.02	0.99	0.99	0.99	0.99	0.99	0.99
NE	0.75	0.67	0.67	1.01	1.00	0.99	0.99	0.98	0.97	0.96	0.96	0.95	0.96	0.96	0.95
NV	0.59	0.50	0.54	0.45	0.45	0.44	0.55	0.47	0.43	0.54	0.46	0.42	0.54	0.46	0.42
NM	0.51	0.48	0.46	0.50	0.47	0.46	0.50	0.47	0.46	0.50	0.47	0.46	0.49	0.46	0.46
NY	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NC	0.51	0.40	0.30	0.48	0.38	0.27	0.48	0.39	0.29	0.49	0.40	0.31	0.49	0.40	0.31

State	Base Case (CPP)			No CPP			2% HRI at $50/kW			4.5% HRI at $50/kW			4.5% HRI at $100/kW		
	2025	2030	2035	2025	2030	2035	2025	2030	2035	2025	2030	2035	2025	2030	2035
ND+SD	0.69	0.67	0.63	0.87	0.91	0.90	0.86	0.89	0.88	0.85	0.86	0.86	0.85	0.86	0.86
OH	0.93	0.93	0.72	0.91	0.87	0.67	0.90	0.85	0.65	0.89	0.86	0.68	0.89	0.85	0.66
OK	0.58	0.47	0.37	0.45	0.40	0.35	0.47	0.39	0.35	0.47	0.39	0.34	0.47	0.39	0.34
PA	0.63	0.61	0.42	0.57	0.55	0.39	0.58	0.55	0.38	0.57	0.53	0.38	0.57	0.53	0.37
SC	0.68	0.59	0.48	0.69	0.58	0.48	0.69	0.59	0.47	0.69	0.60	0.49	0.68	0.60	0.49
TN	0.69	0.65	0.52	0.68	0.60	0.52	0.63	0.59	0.52	0.67	0.63	0.57	0.60	0.56	0.49
TX	1.17	1.10	1.04	1.09	1.06	1.02	1.12	1.08	1.02	1.14	1.10	1.03	1.14	1.10	1.03
UT	0.63	0.63	0.59	0.65	0.65	0.60	0.64	0.64	0.60	0.64	0.64	0.59	0.62	0.62	0.59
VA	0.24	0.14	0.12	0.15	0.13	0.11	0.13	0.10	0.08	0.18	0.16	0.11	0.16	0.13	0.10
WV	0.54	0.49	0.49	0.80	0.76	0.54	0.79	0.74	0.53	0.77	0.73	0.55	0.77	0.73	0.52
WI	0.54	0.46	0.43	0.65	0.65	0.62	0.64	0.63	0.62	0.68	0.67	0.66	0.66	0.66	0.63
WY	0.99	0.97	0.95	0.97	0.94	0.91	0.96	0.92	0.89	0.93	0.91	0.87	0.90	0.89	0.85
Tribal	0.33	0.32	0.29	0.33	0.32	0.29	0.33	0.31	0.29	0.32	0.31	0.28	0.32	0.31	0.28

Table 8-6 Scaling Ratios for Primary $PM_{2.5}$ for Non-Coal EGUs

	Base Case (CPP)			No CPP			2% HRI at $50/kW			4.5% HRI at $50/kW			4.5% HRI at $100/kW		
	2025	2030	2035	2025	2030	2035	2025	2030	2035	2025	2030	2035	2025	2030	2035
AL	0.54	0.54	0.57	0.54	0.53	0.57	0.53	0.54	0.56	0.53	0.54	0.56	0.53	0.53	0.56
AZ	0.59	0.75	0.82	0.55	0.73	0.80	0.55	0.73	0.79	0.53	0.72	0.79	0.53	0.72	0.79
AR	1.91	1.95	1.97	1.89	1.86	1.86	1.89	1.83	1.81	1.85	1.83	1.81	1.88	1.83	1.79
CA	0.36	0.23	0.23	0.37	0.23	0.23	0.37	0.23	0.23	0.37	0.23	0.24	0.37	0.23	0.24
CO	0.53	0.75	0.85	0.40	0.54	0.70	0.40	0.54	0.70	0.40	0.53	0.69	0.41	0.54	0.69
CT+RI	0.32	0.30	0.31	0.33	0.30	0.31	0.33	0.31	0.32	0.33	0.30	0.31	0.33	0.31	0.32
DE+NJ	0.62	0.65	0.62	0.69	0.76	0.77	0.69	0.75	0.77	0.68	0.75	0.76	0.67	0.75	0.76
FL	0.44	0.45	0.47	0.44	0.45	0.47	0.44	0.45	0.47	0.44	0.45	0.47	0.43	0.45	0.47
GA	1.56	1.58	1.72	1.56	1.59	1.76	1.55	1.58	1.74	1.55	1.60	1.73	1.51	1.59	1.70
ID+OR+WA	0.59	0.63	0.65	0.58	0.63	0.65	0.59	0.63	0.65	0.59	0.63	0.65	0.59	0.63	0.65
IL	0.98	1.12	1.22	0.86	1.11	1.16	0.86	1.07	1.16	0.85	1.04	1.16	0.86	1.01	1.17
IN	1.18	1.25	1.86	1.17	1.24	1.77	1.14	1.23	1.74	1.14	1.24	1.71	1.13	1.27	1.76
IA	1.23	1.19	1.44	1.08	1.22	1.54	1.07	1.22	1.55	1.04	1.20	1.52	1.07	1.22	1.55
KS	0.51	0.41	0.58	0.48	0.47	0.64	0.49	0.45	0.65	0.46	0.46	0.61	0.48	0.46	0.62
KY	2.57	4.34	5.35	2.46	4.45	5.37	2.57	4.33	5.38	2.45	4.29	5.14	2.74	4.30	5.44
LA	0.84	0.83	0.89	0.84	0.83	0.87	0.83	0.83	0.88	0.83	0.81	0.87	0.83	0.82	0.88
ME+MA+NH+VT	0.15	0.02	0.02	0.03	0.02	0.02	0.03	0.02	0.02	0.03	0.02	0.02	0.03	0.02	0.02
MD	3.04	3.13	3.25	2.95	2.99	3.05	2.98	2.97	3.06	2.89	2.90	3.04	2.90	2.89	3.14
MI	1.11	1.16	1.68	1.13	1.19	1.49	1.11	1.18	1.48	1.11	1.18	1.40	1.11	1.19	1.47
MN	1.71	1.90	2.19	1.40	1.88	2.25	1.29	1.82	2.20	1.21	1.80	2.17	1.23	1.80	2.19
MS	0.92	0.94	0.98	0.92	0.94	0.98	0.92	0.94	0.94	0.92	0.94	0.94	0.92	0.94	0.94
MO	1.15	1.30	1.58	1.31	1.46	1.76	1.29	1.40	1.72	1.18	1.36	1.68	1.17	1.36	1.65
MT	0.04	0.04	0.04	0.03	0.03	0.04	0.03	0.03	0.04	0.03	0.03	0.04	0.03	0.04	0.04
NE	0.56	0.58	0.58	0.62	0.68	0.92	0.61	0.70	0.90	0.71	0.67	0.90	0.69	0.67	0.90
NV	0.86	1.02	1.11	0.87	1.01	1.09	0.86	1.00	1.09	0.86	1.01	1.09	0.86	1.00	1.10
NM	0.31	0.28	0.27	0.27	0.26	0.27	0.27	0.26	0.27	0.27	0.26	0.27	0.27	0.26	0.27
NY	0.73	0.70	0.71	0.74	0.71	0.72	0.74	0.72	0.72	0.74	0.71	0.72	0.74	0.71	0.71

	Base Case (CPP)			No CPP			2% HRI at $50/kW			4.5% HRI at $50/kW			4.5% HRI at $100/kW		
	2025	2030	2035	2025	2030	2035	2025	2030	2035	2025	2030	2035	2025	2030	2035
NC	1.77	2.05	2.33	1.78	2.12	2.33	1.76	2.11	2.34	1.77	2.09	2.33	1.76	2.08	2.31
ND+SD	2.37	2.41	2.32	1.54	1.81	2.37	1.54	1.85	2.37	1.54	1.86	2.37	1.55	1.77	2.37
OH	2.10	2.17	2.74	2.03	2.19	2.73	2.02	2.13	2.74	1.99	2.13	2.61	1.99	2.16	2.74
OK	1.14	1.15	1.53	1.04	1.06	1.34	0.99	1.06	1.33	0.95	1.05	1.32	0.95	1.04	1.31
PA	1.55	1.54	1.59	1.45	1.44	1.58	1.43	1.44	1.58	1.43	1.44	1.58	1.41	1.44	1.57
SC	0.97	1.26	1.45	0.97	1.29	1.49	0.97	1.25	1.47	0.94	1.20	1.43	0.94	1.20	1.43
TN	2.33	2.37	3.24	2.31	2.44	3.26	2.33	2.51	3.34	2.30	2.37	3.25	2.31	2.48	3.33
TX	0.81	0.79	0.88	0.81	0.80	0.88	0.79	0.79	0.89	0.78	0.78	0.88	0.78	0.78	0.88
UT	0.49	0.63	0.66	0.42	0.54	0.62	0.40	0.54	0.62	0.37	0.49	0.61	0.40	0.51	0.63
VA	1.06	1.19	1.32	1.01	1.11	1.29	1.00	1.11	1.26	1.00	1.10	1.24	1.00	1.09	1.22
WV	1.47	9.66	23.30	1.01	3.74	20.54	0.93	5.34	21.54	0.93	4.02	21.94	0.91	4.75	21.90
WI	2.29	2.30	2.37	2.25	2.26	2.34	2.25	2.26	2.35	2.20	2.23	2.27	2.24	2.26	2.30
WY	0.20	4.37	4.53	0.09	4.37	4.53	0.28	4.37	4.53	0.22	4.37	4.53	0.37	4.37	4.43
Tribal	14.78	16.83	17.94	13.58	16.09	17.63	13.39	16.08	17.50	13.12	15.91	17.33	13.23	15.99	17.39

Table 8-7 Scaling Ratios for Sulfate for Coal EGUs

	Base Case (CPP)			No CPP			2% HRI at $50/kW			4.5% HRI at $50/kW			4.5% HRI at $100/kW		
State	2025	2030	2035	2025	2030	2035	2025	2030	2035	2025	2030	2035	2025	2030	2035
AL	0.91	1.02	0.85	0.71	0.91	0.79	0.71	0.89	0.77	0.76	0.94	0.79	0.74	0.89	0.77
AZ	1.02	0.99	0.81	1.02	0.99	0.81	1.00	0.97	0.80	0.98	0.94	0.78	0.98	0.94	0.78
AR	1.47	1.97	1.69	1.92	2.45	2.35	2.10	2.50	2.35	2.28	2.57	2.40	2.25	2.55	2.37
CA	0.98	0.00	0.00	0.98	0.00	0.00	0.96	0.00	0.00	0.93	0.00	0.00	0.93	0.00	0.00
CO	0.78	0.71	0.66	0.98	1.00	0.90	0.96	0.98	0.88	0.95	0.95	0.86	0.95	0.95	0.86
CT+RI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DE+NJ	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FL	0.77	0.74	0.88	0.67	0.69	0.86	0.72	0.72	0.86	0.74	0.76	0.87	0.73	0.76	0.86
GA	1.72	1.65	1.45	2.11	1.74	1.53	2.04	1.72	1.63	2.06	1.71	1.64	2.01	1.71	1.62
IL	0.86	0.83	0.77	0.85	0.83	0.75	0.84	0.83	0.74	0.82	0.81	0.75	0.81	0.79	0.73
IN	0.96	0.91	0.81	0.95	0.90	0.80	0.94	0.88	0.80	0.93	0.87	0.79	0.93	0.87	0.79
IA	0.40	0.37	0.35	0.50	0.47	0.46	0.49	0.47	0.46	0.48	0.47	0.46	0.48	0.46	0.45
KS	1.96	1.70	1.69	2.53	2.45	2.26	2.50	2.44	2.26	2.50	2.41	2.27	2.51	2.40	2.26
KY	0.34	0.34	0.24	0.33	0.30	0.23	0.32	0.30	0.23	0.32	0.30	0.24	0.31	0.30	0.23
LA	0.23	0.26	0.30	0.22	0.24	0.29	0.22	0.23	0.28	0.21	0.28	0.28	0.21	0.28	0.27
ME+MA+NH+VT	0.67	0.67	0.67	0.52	0.52	0.52	0.17	0.17	0.17	0.41	0.41	0.41	0.01	0.01	0.01
MD	0.05	0.00	0.00	0.04	0.00	0.00	0.05	0.01	0.00	0.05	0.03	0.00	0.06	0.03	0.00
MI	0.77	0.64	0.61	0.96	0.98	0.74	0.95	0.97	0.77	0.93	0.95	0.87	0.94	0.94	0.80
MN	1.33	1.31	1.29	1.38	1.31	1.30	1.36	1.30	1.29	1.31	1.30	1.26	1.32	1.29	1.26
MS	0.86	0.91	0.91	0.70	0.83	0.86	0.68	0.82	0.89	0.71	0.91	0.91	0.84	0.90	0.91
MO	1.10	1.12	1.09	1.20	1.27	1.24	1.18	1.24	1.22	1.20	1.22	1.20	1.20	1.21	1.18
MT	0.46	0.55	0.51	0.52	0.61	0.61	0.51	0.60	0.60	0.50	0.58	0.58	0.50	0.58	0.58
NE	0.72	0.69	0.87	0.78	0.78	0.96	0.76	0.76	0.94	0.74	0.74	0.92	0.74	0.74	0.92
NV	5.04	4.47	4.67	2.89	2.93	2.85	3.54	3.03	2.79	3.45	2.96	2.72	3.49	2.99	2.76
NM	1.40	1.30	1.26	1.39	1.30	1.27	1.38	1.29	1.28	1.37	1.28	1.27	1.36	1.28	1.27
NY	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01
NC	0.57	0.46	0.37	0.53	0.44	0.35	0.54	0.45	0.36	0.54	0.46	0.39	0.54	0.46	0.39
ND+SD	0.56	0.55	0.49	0.61	0.64	0.63	0.60	0.62	0.62	0.59	0.61	0.61	0.59	0.61	0.61

State	Base Case (CPP)			No CPP			2% HRI at $50/kW			4.5% HRI at $50/kW			4.5% HRI at $100/kW		
	2025	2030	2035	2025	2030	2035	2025	2030	2035	2025	2030	2035	2025	2030	2035
OH	0.83	0.83	0.58	0.69	0.76	0.58	0.69	0.75	0.56	0.69	0.76	0.60	0.68	0.76	0.57
OK	1.49	1.14	0.98	1.24	0.97	0.88	1.26	0.95	0.87	1.24	0.93	0.85	1.24	0.93	0.85
PA	0.50	0.48	0.34	0.45	0.45	0.32	0.46	0.44	0.31	0.45	0.43	0.31	0.44	0.42	0.30
SC	2.51	2.08	1.65	2.52	2.12	1.67	2.51	2.16	1.62	2.49	2.19	1.66	2.49	2.20	1.67
TN	0.66	0.59	0.45	0.66	0.56	0.45	0.62	0.54	0.46	0.64	0.58	0.49	0.59	0.53	0.44
TX	0.97	0.91	0.87	0.88	0.88	0.84	0.91	0.90	0.82	0.94	0.90	0.83	0.94	0.89	0.84
UT	1.12	1.26	1.42	1.14	1.27	1.39	1.12	1.25	1.36	1.12	1.25	1.38	1.07	1.21	1.32
VA	0.79	0.55	0.45	0.52	0.51	0.44	0.40	0.39	0.31	0.57	0.57	0.43	0.49	0.49	0.37
WV	0.77	0.76	0.81	1.47	1.34	0.81	1.44	1.31	0.79	1.39	1.29	0.82	1.39	1.29	0.78
WI	0.82	0.66	0.63	0.98	0.98	0.94	0.98	0.97	0.94	1.05	1.02	1.01	1.01	1.01	0.96
WY	0.79	0.59	0.58	0.79	0.58	0.64	0.77	0.56	0.63	0.75	0.55	0.61	0.74	0.54	0.60
Tribal	1.22	1.18	1.14	1.22	1.18	1.13	1.21	1.17	1.13	1.20	1.16	1.12	1.18	1.15	1.11

Table 8-8 Scaling Ratios for Sulfate for Non-Coal EGUs

	Base Case (CPP)			No CPP			2% HRI at $50/kW			4.5% HRI at $50/kW			4.5% HRI at $100/kW		
	2025	2030	2035	2025	2030	2035	2025	2030	2035	2025	2030	2035	2025	2030	2035
AL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
AZ	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
AR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CA	0.19	0.01	0.01	0.19	0.01	0.02	0.19	0.01	0.02	0.19	0.01	0.02	0.19	0.01	0.02
CO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CT+RI	1.96	1.96	1.96	1.96	1.96	1.96	1.96	1.96	1.96	1.96	1.96	1.96	1.96	1.96	1.96
DE+NJ	2.67	2.67	2.67	2.67	2.67	2.67	2.67	2.67	2.67	2.67	2.67	2.67	2.67	2.67	2.67
FL	0.68	0.68	0.67	0.68	0.68	0.67	0.68	0.68	0.67	0.68	0.68	0.67	0.68	0.68	0.67
GA	0.05	0.06	0.09	0.05	0.05	0.09	0.04	0.05	0.09	0.04	0.05	0.05	0.04	0.05	0.05
ID+OR+WA	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
IL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
IN	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
IA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
KS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
KY	0.03	0.03	0.02	0.03	0.03	0.02	0.03	0.03	0.02	0.03	0.03	0.02	0.03	0.03	0.02
LA	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
ME+MA+NH+VT	0.59	0.54	0.59	0.59	0.54	0.59	0.59	0.54	0.59	0.59	0.54	0.59	0.58	0.54	0.59
MD	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45
MI	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
MN	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36
MS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NV	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NY	0.69	0.64	0.64	0.69	0.64	0.64	0.69	0.64	0.64	0.69	0.64	0.64	0.69	0.64	0.64
NC	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01

	Base Case (CPP)			No CPP			2% HRI at $50/kW			4.5% HRI at $50/kW			4.5% HRI at $100/kW		
	2025	2030	2035	2025	2030	2035	2025	2030	2035	2025	2030	2035	2025	2030	2035
ND+SD	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
OH	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
OK	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PA	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
SC	0.01	0.01	0.01	0.01	0.01	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
TN	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TX	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
UT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
VA	0.21	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.21	0.20	0.20	0.21	0.20	0.20
WV	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WY	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tribal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table 8-9 Scaling Ratios for Nitrate for Coal EGUs

	Base Case (CPP)			No CPP			2% HRI at $50/kW			4.5% HRI at $50/kW			4.5% HRI at $100/kW		
State	2025	2030	2035	2025	2030	2035	2025	2030	2035	2025	2030	2035	2025	2030	2035
AL	0.43	0.48	0.44	0.34	0.45	0.40	0.35	0.44	0.39	0.39	0.48	0.42	0.37	0.44	0.39
AZ	0.77	0.77	0.68	0.77	0.77	0.68	0.76	0.75	0.66	0.74	0.73	0.65	0.74	0.73	0.65
AR	0.87	0.98	0.82	1.02	1.14	1.10	1.08	1.15	1.11	1.13	1.17	1.13	1.13	1.16	1.12
CA	0.18	0.00	0.00	0.18	0.00	0.00	0.17	0.00	0.00	0.17	0.00	0.00	0.17	0.00	0.00
CO	0.92	0.81	0.77	0.89	0.92	0.83	0.88	0.90	0.82	0.86	0.88	0.80	0.86	0.88	0.80
CT+RI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DE+NJ	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FL	0.52	0.54	0.62	0.47	0.50	0.60	0.49	0.53	0.60	0.51	0.55	0.60	0.49	0.54	0.60
GA	0.37	0.43	0.39	0.44	0.45	0.41	0.43	0.46	0.44	0.44	0.46	0.44	0.43	0.46	0.44
IL	1.10	1.05	0.97	1.06	1.04	0.95	1.05	1.03	0.94	1.05	1.02	0.95	1.02	0.98	0.91
IN	0.79	0.80	0.69	0.78	0.78	0.68	0.77	0.77	0.67	0.76	0.76	0.67	0.76	0.76	0.66
IA	0.98	0.91	0.84	1.25	1.19	1.17	1.23	1.18	1.17	1.22	1.18	1.15	1.22	1.16	1.15
KS	0.85	0.71	0.73	1.08	1.03	0.93	1.08	1.03	0.94	1.07	1.02	0.94	1.07	1.02	0.94
KY	0.53	0.49	0.36	0.52	0.45	0.35	0.51	0.44	0.35	0.50	0.45	0.36	0.50	0.45	0.35
LA	0.22	0.25	0.29	0.21	0.23	0.28	0.21	0.22	0.27	0.21	0.27	0.27	0.20	0.26	0.26
ME+MA+NH+VT	0.23	0.23	0.23	0.18	0.18	0.18	0.06	0.06	0.06	0.14	0.14	0.14	0.00	0.00	0.00
MD	0.07	0.00	0.00	0.05	0.00	0.00	0.07	0.01	0.00	0.07	0.03	0.00	0.07	0.04	0.00
MI	0.91	0.81	0.75	1.12	1.14	0.95	1.10	1.13	0.97	1.08	1.10	1.04	1.08	1.10	0.99
MN	1.17	0.94	0.92	1.30	0.98	0.97	1.25	0.96	0.96	1.18	0.98	0.93	1.18	0.98	0.93
MS	0.29	0.50	0.50	0.23	0.41	0.49	0.23	0.41	0.49	0.24	0.53	0.53	0.36	0.52	0.52
MO	0.84	0.76	0.71	1.07	1.03	0.97	1.04	0.99	0.94	1.07	1.01	0.96	1.03	0.98	0.92
MT	0.91	0.91	0.85	0.97	0.97	0.97	0.95	0.95	0.95	0.92	0.92	0.92	0.92	0.92	0.92
NE	0.82	0.75	0.76	1.14	1.14	1.13	1.12	1.12	1.11	1.09	1.09	1.08	1.09	1.09	1.08
NV	1.75	1.55	1.62	1.01	1.02	0.99	1.24	1.06	0.97	1.20	1.03	0.95	1.22	1.04	0.96
NM	0.75	0.67	0.63	0.74	0.66	0.62	0.73	0.65	0.62	0.71	0.64	0.61	0.71	0.63	0.61
NY	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NC	0.74	0.60	0.42	0.71	0.57	0.37	0.71	0.58	0.39	0.71	0.59	0.44	0.71	0.59	0.44
ND+SD	0.58	0.56	0.53	0.81	0.84	0.83	0.80	0.83	0.82	0.79	0.80	0.80	0.79	0.80	0.80

	Base Case (CPP)			No CPP			2% HRI at $50/kW			4.5% HRI at $50/kW			4.5% HRI at $100/kW		
State	2025	2030	2035	2025	2030	2035	2025	2030	2035	2025	2030	2035	2025	2030	2035
OH	1.14	1.13	0.86	1.11	1.04	0.79	1.10	1.03	0.78	1.10	1.06	0.81	1.09	1.04	0.79
OK	1.70	1.40	1.10	1.34	1.20	1.06	1.40	1.18	1.05	1.40	1.16	1.03	1.39	1.16	1.03
PA	0.93	0.87	0.55	0.82	0.72	0.52	0.83	0.72	0.51	0.82	0.70	0.51	0.82	0.70	0.50
SC	0.99	0.87	0.72	1.02	0.86	0.72	1.02	0.87	0.70	1.00	0.88	0.72	1.00	0.88	0.72
TN	0.61	0.58	0.47	0.60	0.54	0.48	0.56	0.53	0.47	0.59	0.57	0.51	0.53	0.51	0.44
TX	1.09	1.02	0.94	1.02	0.99	0.92	1.04	0.99	0.91	1.06	1.00	0.93	1.05	1.00	0.93
UT	1.08	1.07	1.01	1.15	1.15	1.06	1.13	1.13	1.05	1.11	1.11	1.02	1.10	1.10	1.04
VA	0.27	0.16	0.11	0.17	0.15	0.11	0.14	0.11	0.07	0.20	0.17	0.10	0.18	0.14	0.09
WV	0.63	0.57	0.56	0.95	0.88	0.62	0.93	0.86	0.61	0.91	0.85	0.62	0.91	0.85	0.60
WI	0.56	0.47	0.44	0.67	0.67	0.64	0.67	0.66	0.64	0.71	0.70	0.69	0.69	0.68	0.65
WY	1.05	0.86	0.85	1.04	0.84	0.83	1.02	0.83	0.81	1.00	0.81	0.79	0.98	0.80	0.78
Tribal	0.73	0.71	0.66	0.75	0.74	0.67	0.74	0.73	0.67	0.73	0.71	0.65	0.72	0.71	0.66

Table 8-10 Scaling Ratios for Nitrate for Non-Coal EGUs

	Base Case (CPP)			No CPP			2% HRI at $50/kW			4.5% HRI at $50/kW			4.5% HRI at $100/kW		
State	2025	2030	2035	2025	2030	2035	2025	2030	2035	2025	2030	2035	2025	2030	2035
AL	0.79	0.90	1.12	0.80	0.89	1.12	0.77	0.88	1.09	0.78	0.90	1.08	0.77	0.87	1.07
AZ	0.23	0.30	0.34	0.22	0.30	0.33	0.22	0.30	0.33	0.21	0.30	0.33	0.21	0.30	0.33
AR	0.79	0.79	0.82	0.79	0.79	0.81	0.79	0.78	0.80	0.78	0.78	0.80	0.78	0.79	0.79
CA	3.42	0.57	0.66	2.99	0.57	0.66	2.98	0.57	0.66	2.98	0.58	0.67	2.97	0.58	0.67
CO	0.39	0.56	0.62	0.23	0.35	0.45	0.23	0.35	0.45	0.23	0.35	0.45	0.24	0.36	0.44
CT+RI	1.19	1.18	1.19	1.20	1.18	1.19	1.20	1.19	1.20	1.20	1.19	1.19	1.21	1.19	1.20
DE+NJ	1.25	1.30	1.29	1.33	1.42	1.45	1.32	1.40	1.45	1.32	1.39	1.44	1.31	1.38	1.42
FL	1.00	1.02	1.01	1.01	1.03	1.01	1.00	1.02	1.02	0.99	1.01	1.02	0.98	1.01	1.02
GA	1.19	1.32	1.33	1.18	1.33	1.31	1.14	1.32	1.28	1.21	1.36	1.25	1.10	1.35	1.24
ID+OR+WA	0.58	0.66	0.69	0.57	0.65	0.67	0.57	0.65	0.67	0.58	0.65	0.67	0.58	0.65	0.68
IL	0.87	0.94	1.00	0.80	0.93	0.98	0.80	0.93	0.98	0.79	0.92	0.98	0.80	0.91	0.99
IN	1.00	1.03	1.24	1.01	1.05	1.23	0.97	1.03	1.24	0.97	1.03	1.24	0.96	1.03	1.24
IA	1.01	1.01	1.17	0.91	0.99	1.24	0.90	1.03	1.25	0.90	1.01	1.22	0.91	1.04	1.26
KS	1.14	0.86	1.04	1.14	1.08	1.18	1.14	1.07	1.23	1.12	1.11	1.21	1.14	1.11	1.21
KY	1.23	1.47	1.54	1.26	1.41	1.54	1.23	1.37	1.55	1.14	1.36	1.51	1.12	1.31	1.54
LA	0.48	0.41	0.43	0.48	0.41	0.42	0.48	0.41	0.42	0.48	0.40	0.42	0.48	0.41	0.41
ME+MA+NH+VT	1.07	0.64	0.71	0.73	0.65	0.71	0.73	0.64	0.71	0.73	0.64	0.71	0.72	0.64	0.71
MD	1.26	1.25	1.22	1.26	1.28	1.21	1.25	1.25	1.21	1.24	1.24	1.19	1.24	1.23	1.19
MI	1.15	1.17	1.23	1.17	1.20	1.23	1.16	1.20	1.23	1.16	1.21	1.23	1.16	1.20	1.21
MN	0.71	0.72	0.79	0.68	0.73	0.80	0.67	0.73	0.80	0.66	0.73	0.80	0.66	0.74	0.81
MS	0.44	0.51	0.51	0.42	0.48	0.49	0.42	0.48	0.50	0.43	0.48	0.49	0.41	0.49	0.50
MO	0.48	0.49	0.59	0.48	0.52	0.62	0.47	0.51	0.63	0.45	0.51	0.62	0.46	0.51	0.62
MT	0.01	0.01	0.02	0.01	0.01	0.02	0.01	0.01	0.02	0.01	0.01	0.02	0.01	0.01	0.02
NE	0.78	0.92	0.92	0.88	0.94	0.97	0.87	0.95	0.97	0.93	0.94	0.97	0.90	0.94	0.97
NV	0.84	1.10	1.32	0.90	1.02	1.16	0.87	1.03	1.16	0.88	1.03	1.17	0.87	1.03	1.16
NM	0.41	0.23	0.20	0.41	0.22	0.19	0.41	0.22	0.19	0.41	0.22	0.18	0.41	0.22	0.18
NY	1.00	0.98	0.98	1.01	0.99	0.99	1.02	0.99	0.99	1.01	0.99	1.00	1.02	0.99	0.99
NC	0.88	0.86	0.90	0.89	0.86	0.89	0.88	0.87	0.91	0.90	0.89	0.97	0.89	0.89	0.95

State	Base Case (CPP)			No CPP			2% HRI at $50/kW			4.5% HRI at $50/kW			4.5% HRI at $100/kW		
	2025	2030	2035	2025	2030	2035	2025	2030	2035	2025	2030	2035	2025	2030	2035
ND+SD	0.42	0.42	0.42	0.31	0.34	0.46	0.31	0.35	0.46	0.31	0.35	0.46	0.29	0.33	0.46
OH	1.59	1.66	1.80	1.57	1.72	1.75	1.55	1.69	1.73	1.50	1.65	1.66	1.50	1.67	1.70
OK	0.80	0.78	1.00	0.74	0.75	0.93	0.70	0.74	0.94	0.68	0.74	0.94	0.69	0.74	0.94
PA	1.40	1.32	1.30	1.24	1.18	1.29	1.20	1.17	1.29	1.20	1.17	1.27	1.18	1.16	1.23
SC	0.76	0.78	0.80	0.77	0.76	0.79	0.76	0.75	0.78	0.73	0.72	0.76	0.69	0.70	0.76
TN	0.78	0.93	1.05	0.77	0.92	1.04	0.78	0.93	1.06	0.75	0.88	1.02	0.77	0.97	1.03
TX	0.85	0.84	0.91	0.85	0.84	0.90	0.84	0.84	0.91	0.82	0.83	0.90	0.82	0.83	0.90
UT	0.39	0.47	0.49	0.36	0.41	0.47	0.35	0.41	0.47	0.34	0.39	0.47	0.35	0.40	0.48
VA	1.04	1.17	1.22	0.98	1.11	1.19	0.97	1.10	1.16	0.97	1.09	1.15	0.97	1.07	1.13
WV	0.20	0.53	1.04	0.18	0.33	0.95	0.13	0.36	0.99	0.13	0.28	1.00	0.13	0.31	1.00
WI	1.00	1.01	1.06	0.96	0.97	1.03	0.95	0.97	1.04	0.93	0.97	1.01	0.94	0.99	1.04
WY	0.03	0.62	0.64	0.01	0.62	0.64	0.04	0.62	0.64	0.03	0.62	0.64	0.05	0.62	0.63
Tribal	8.17	9.05	9.83	7.85	8.81	9.63	7.79	8.84	9.60	7.67	8.76	9.56	7.72	8.82	9.49

Table 8-11 Scaling Ratios for Ozone for Coal EGUs

	Base Case (CPP)			No CPP			2% HRI at $50/kW			4.5% HRI at $50/kW			4.5% HRI at $100/kW		
State	2025	2030	2035	2025	2030	2035	2025	2030	2035	2025	2030	2035	2025	2030	2035
AL	0.53	0.61	0.65	0.43	0.57	0.61	0.44	0.55	0.59	0.50	0.60	0.64	0.47	0.53	0.57
AZ	0.75	0.78	0.80	0.75	0.78	0.80	0.73	0.76	0.78	0.71	0.74	0.76	0.71	0.74	0.76
AR	0.94	1.18	1.20	1.04	1.42	1.46	1.14	1.45	1.47	1.17	1.42	1.45	1.17	1.42	1.45
CA	0.17	0.00	0.00	0.17	0.00	0.00	0.17	0.00	0.00	0.17	0.00	0.00	0.17	0.00	0.00
CO	0.93	0.94	0.92	0.91	0.94	0.92	0.90	0.93	0.90	0.88	0.89	0.88	0.88	0.91	0.88
CT+RI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DE+NJ	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FL	0.66	0.79	1.05	0.65	0.73	1.03	0.65	0.77	1.03	0.64	0.78	1.04	0.63	0.77	1.03
GA	0.61	0.79	0.89	0.72	0.81	0.93	0.71	0.80	1.02	0.70	0.80	0.99	0.69	0.80	0.99
IL	1.00	1.02	0.96	0.99	1.01	0.94	0.98	1.00	0.95	0.95	0.98	0.95	0.92	0.93	0.92
IN	0.80	0.82	0.68	0.79	0.79	0.68	0.77	0.78	0.67	0.76	0.77	0.65	0.76	0.77	0.65
IA	0.85	0.84	0.82	1.10	1.11	1.09	1.07	1.09	1.09	1.07	1.08	1.08	1.07	1.08	1.08
KS	0.86	0.90	0.90	1.07	1.12	1.11	1.04	1.09	1.09	1.02	1.06	1.08	1.02	1.06	1.09
KY	0.60	0.56	0.52	0.60	0.54	0.49	0.59	0.54	0.50	0.58	0.53	0.53	0.57	0.55	0.50
LA	0.32	0.33	0.44	0.31	0.34	0.44	0.30	0.32	0.42	0.30	0.38	0.42	0.29	0.36	0.41
ME+MA+NH+VT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MD	0.09	0.00	0.00	0.04	0.00	0.00	0.08	0.00	0.00	0.09	0.03	0.00	0.09	0.03	0.00
MI	0.81	0.82	0.77	1.02	1.05	0.94	1.00	1.02	0.95	0.99	1.00	0.98	0.99	1.00	0.93
MN	1.20	0.96	0.94	1.28	0.95	0.95	1.23	0.95	0.94	1.16	1.03	0.92	1.16	1.01	0.92
MS	0.31	0.66	0.66	0.23	0.66	0.66	0.23	0.65	0.65	0.26	0.63	0.63	0.50	0.63	0.63
MO	0.93	0.94	0.93	1.08	1.10	1.10	1.04	1.06	1.06	1.05	1.06	1.08	1.02	1.03	1.04
MT	1.02	1.02	0.95	1.08	1.08	1.08	1.06	1.06	1.06	1.03	1.03	1.03	1.03	1.03	1.03
NE	0.92	0.89	0.91	1.15	1.15	1.15	1.13	1.13	1.13	1.10	1.10	1.10	1.10	1.10	1.10
NV	0.71	0.88	1.05	0.71	0.83	0.78	0.69	0.83	0.76	0.68	0.81	0.74	0.68	0.81	0.74
NM	0.84	0.84	0.84	0.82	0.82	0.82	0.81	0.81	0.81	0.79	0.79	0.79	0.78	0.78	0.78
NY	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NC	0.79	0.69	0.57	0.78	0.65	0.50	0.79	0.65	0.55	0.77	0.67	0.63	0.77	0.67	0.63
ND+SD	0.66	0.67	0.66	0.84	0.91	0.89	0.84	0.89	0.88	0.81	0.87	0.86	0.81	0.87	0.86

State	Base Case (CPP)			No CPP			2% HRI at $50/kW			4.5% HRI at $50/kW			4.5% HRI at $100/kW		
	2025	2030	2035	2025	2030	2035	2025	2030	2035	2025	2030	2035	2025	2030	2035
OH	1.09	1.09	0.99	1.06	1.08	0.91	1.06	1.06	0.90	1.04	1.03	0.95	1.04	1.03	0.92
OK	1.80	1.66	1.57	1.53	1.57	1.58	1.58	1.54	1.54	1.57	1.51	1.51	1.55	1.51	1.51
PA	0.72	0.72	0.59	0.65	0.66	0.57	0.67	0.68	0.56	0.66	0.66	0.55	0.66	0.66	0.55
SC	0.99	0.95	0.94	1.00	0.95	0.95	0.97	0.95	0.92	0.97	0.95	0.97	0.97	0.95	0.97
TN	0.62	0.65	0.57	0.60	0.59	0.61	0.55	0.59	0.61	0.60	0.65	0.65	0.52	0.56	0.57
TX	1.02	1.11	1.14	0.97	1.11	1.14	0.98	1.09	1.12	0.99	1.07	1.09	0.98	1.07	1.09
UT	1.12	1.12	1.12	1.19	1.19	1.19	1.17	1.17	1.17	1.15	1.15	1.15	1.14	1.14	1.14
VA	0.25	0.18	0.14	0.18	0.18	0.14	0.16	0.13	0.10	0.23	0.17	0.13	0.21	0.15	0.11
WV	0.75	0.75	0.81	1.06	1.06	0.85	1.04	1.04	0.85	1.02	1.02	0.85	1.03	1.02	0.84
WI	0.45	0.44	0.41	0.57	0.64	0.62	0.56	0.61	0.60	0.61	0.65	0.64	0.59	0.63	0.61
WY	1.01	0.83	0.83	1.00	0.81	0.81	0.99	0.80	0.80	0.96	0.79	0.78	0.95	0.79	0.79
Tribal	0.76	0.77	0.78	0.78	0.79	0.80	0.77	0.78	0.79	0.75	0.76	0.77	0.75	0.76	0.76

Table 8-12 Scaling Ratios for Ozone for Non-Coal EGUs

	Base Case (CPP)			No CPP			2% HRI at $50/kW			4.5% HRI at $50/kW			4.5% HRI at $100/kW		
	2025	2030	2035	2025	2030	2035	2025	2030	2035	2025	2030	2035	2025	2030	2035
AL	1.19	1.22	1.16	1.20	1.21	1.15	1.18	1.21	1.14	1.17	1.21	1.14	1.17	1.21	1.13
AZ	0.25	0.31	0.32	0.24	0.32	0.32	0.24	0.32	0.32	0.24	0.32	0.33	0.24	0.32	0.32
AR	0.66	0.63	0.58	0.67	0.59	0.53	0.67	0.58	0.52	0.65	0.59	0.54	0.66	0.60	0.53
CA	2.82	0.55	0.73	2.39	0.55	0.73	2.39	0.55	0.72	2.39	0.56	0.74	2.39	0.56	0.74
CO	0.46	0.57	0.49	0.31	0.37	0.42	0.31	0.37	0.42	0.31	0.37	0.42	0.31	0.37	0.42
CT+RI	1.15	1.16	1.19	1.16	1.16	1.19	1.16	1.17	1.20	1.16	1.17	1.20	1.17	1.17	1.21
DE+NJ	1.15	1.21	1.12	1.19	1.26	1.25	1.19	1.25	1.24	1.19	1.25	1.24	1.19	1.24	1.22
FL	0.97	0.97	0.90	0.97	0.97	0.90	0.96	0.96	0.93	0.96	0.96	0.93	0.95	0.96	0.93
GA	1.22	1.35	1.15	1.20	1.41	1.14	1.14	1.39	1.10	1.29	1.47	1.03	1.10	1.46	1.02
ID+OR+WA	0.46	0.52	0.57	0.45	0.52	0.55	0.45	0.52	0.55	0.45	0.52	0.55	0.46	0.52	0.56
IL	1.01	1.00	1.09	0.95	0.99	1.06	0.95	1.00	1.08	0.95	1.01	1.08	0.96	1.02	1.09
IN	1.19	1.14	1.36	1.20	1.17	1.33	1.16	1.18	1.34	1.17	1.18	1.36	1.15	1.18	1.36
IA	1.15	1.10	1.27	1.03	1.03	1.40	1.02	1.10	1.43	1.02	1.10	1.39	1.04	1.14	1.45
KS	1.58	1.10	1.41	1.57	1.41	1.61	1.57	1.42	1.69	1.55	1.47	1.65	1.57	1.48	1.66
KY	1.28	1.17	1.14	1.37	1.28	1.15	1.29	1.21	1.16	1.13	1.20	1.12	1.09	1.10	1.13
LA	0.57	0.50	0.39	0.57	0.49	0.39	0.57	0.50	0.39	0.57	0.49	0.38	0.56	0.50	0.38
ME+MA+NH+VT	1.10	0.66	0.79	0.75	0.66	0.79	0.75	0.66	0.79	0.75	0.66	0.79	0.73	0.66	0.79
MD	1.13	1.08	1.01	1.12	1.12	1.02	1.12	1.11	1.02	1.11	1.11	1.00	1.11	1.08	1.00
MI	1.15	1.14	1.18	1.19	1.20	1.18	1.17	1.20	1.17	1.17	1.21	1.20	1.18	1.20	1.16
MN	0.75	0.73	0.87	0.72	0.75	0.89	0.71	0.75	0.88	0.70	0.75	0.87	0.71	0.76	0.87
MS	0.41	0.47	0.38	0.39	0.46	0.36	0.39	0.47	0.37	0.39	0.46	0.34	0.37	0.47	0.36
MO	0.59	0.50	0.57	0.54	0.54	0.61	0.54	0.54	0.65	0.54	0.55	0.63	0.56	0.55	0.64
MT	0.03	0.03	0.04	0.02	0.02	0.05	0.02	0.02	0.05	0.02	0.02	0.05	0.02	0.03	0.05
NE	0.71	0.88	0.88	0.83	0.89	0.93	0.82	0.90	0.92	0.88	0.89	0.92	0.84	0.89	0.92
NV	0.67	0.78	1.05	0.68	0.77	0.98	0.68	0.77	0.98	0.68	0.76	0.98	0.68	0.77	0.98
NM	0.50	0.38	0.26	0.52	0.38	0.28	0.51	0.38	0.28	0.51	0.38	0.27	0.51	0.38	0.27
NY	0.92	0.90	0.88	0.93	0.91	0.90	0.94	0.91	0.90	0.94	0.91	0.90	0.94	0.91	0.89
NC	1.10	0.95	0.89	1.11	0.98	0.88	1.11	1.02	0.88	1.10	1.05	0.95	1.09	1.05	0.94

	Base Case (CPP)			No CPP			2% HRI at $50/kW			4.5% HRI at $50/kW			4.5% HRI at $100/kW		
	2025	2030	2035	2025	2030	2035	2025	2030	2035	2025	2030	2035	2025	2030	2035
ND+SD	0.52	0.52	0.54	0.48	0.51	0.60	0.48	0.51	0.60	0.48	0.51	0.60	0.44	0.51	0.60
OH	1.56	1.51	1.56	1.53	1.56	1.66	1.50	1.51	1.62	1.49	1.52	1.52	1.48	1.53	1.54
OK	1.01	0.93	0.91	0.94	0.90	0.94	0.92	0.91	0.96	0.91	0.91	0.97	0.92	0.90	0.97
PA	1.09	1.00	0.97	1.01	0.94	0.96	0.97	0.94	0.96	0.98	0.94	0.96	0.95	0.94	0.93
SC	0.96	0.87	0.82	0.97	0.84	0.81	0.96	0.83	0.79	0.91	0.78	0.77	0.83	0.76	0.77
TN	0.64	0.67	0.75	0.63	0.65	0.75	0.64	0.66	0.76	0.63	0.63	0.74	0.63	0.65	0.73
TX	0.93	0.87	0.86	0.94	0.88	0.86	0.92	0.88	0.87	0.90	0.88	0.88	0.91	0.89	0.88
UT	0.26	0.27	0.28	0.23	0.25	0.25	0.22	0.25	0.24	0.21	0.23	0.24	0.23	0.24	0.25
VA	0.97	1.06	0.98	0.92	0.99	0.97	0.91	0.99	0.97	0.91	0.99	0.96	0.91	0.96	0.96
WV	0.18	0.45	1.02	0.28	0.38	0.89	0.18	0.35	0.93	0.18	0.22	0.94	0.18	0.25	0.94
WI	0.90	0.90	0.95	0.83	0.84	0.92	0.82	0.84	0.93	0.81	0.84	0.91	0.83	0.86	0.93
WY	0.04	0.08	0.08	0.02	0.08	0.08	0.06	0.08	0.08	0.05	0.08	0.08	0.08	0.08	0.08
Tribal	11.16	12.28	12.10	10.83	12.31	12.03	10.80	12.44	12.07	10.73	12.36	12.17	10.82	12.42	11.95

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 base case and each of the four illustrative scenarios 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)[1] 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)[2]. 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;

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[1] Software download and documentation available at https://www.epa.gov/scram/photochemical-modeling-tools

[2] Three years of ambient data is used to provide a more representative picture of air pollution concentrations.

- $Monitor_{x,s,q,2010-2012}$ 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

- $Model_{x,s,q,2011}$ 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 base case and illustrative scenarios for 2025/2030/2035, we take the ratio of the modeled future year[3] 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

[3] In this analysis the "future year" modeled concentration is the result of Equations 9, 10 or 11 that represents either the base case or one of the illustrative scenarios for 2025, 2030, or 2035.

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.

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 $PM_{2.5}$.

8.5 References

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