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Regulatory Impact Analysis for Proposed Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category

United States
Environmental Protection
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U.S. Environmental Protection Agency
Office of Water (4303T)
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Table of Contents

List of Tables

List of Figures

Abbreviations

ACE	Affordable Clean Energy
AEO	Annual Energy Outlook
ASCC	Alaska Systems Coordinating Council
BAT	Best available technology economically achievable
BCA	Benefit and Cost Analysis
BEA	U.S. Bureau of Economic Analysis
BLS	U.S. Bureau of Labor Statistics
BMP	Best management practice
BPT	Best practicable control technology currently available
BSER	Best system of emissions reduction
CAA	Clean Air Act
CCI	Construction cost index
CCR	Coal combustion residuals
CPP	Clean Power Plan
CSAPR	Cross-State Air Pollution Rule
CWA	Clean Water Act
DOE	Department of Energy
EA	Environmental Assessment
ECI	Employment Cost Index
EGU	Electricity generating units
EIA	Energy Information Administration
EJ	Environmental justice
ELGs	Effluent limitations guidelines and standards
EO	Executive Order
EPA	U.S. Environmental Protection Agency
FGD	Flue gas desulfurization
FOM	Fixed O&M
FR	Federal Register
FRCC	Florida Reliability Coordinating Council
GDP	Gross domestic product
HICC	Hawaii Coordinating Council
HRI	Heat rate improvement
HRTR	High Hydraulic Residence Time Reduction
IPM	Integrated Planning Model
LRTR	Low Hydraulic Residence Time Reduction
MATS	Mercury and Air Toxics Standards
MRO	Midwest Reliability Organization
NAICS	North American Industry Classification System
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
NPDES	National Pollutant Discharge Elimination System
NSPS	New Source Performance Standards

O&M	Operation and maintenance
OMB	Office of Management and Budget
POTW	Publicly owned treatment works
PSES	Pretreatment Standards for Existing Sources
PSNS	Pretreatment Standards for New Sources
RFA	Regulatory Flexibility Act
RFC	Reliability First Corporation
RGGI	Regional Greenhouse Gas Initiative
SBA	Small Business Administration
SBREFA	Small Business Regulatory Enforcement Fairness Act
SERC	SERC Reliability Corporation
SISNOSE	Significant impact on a substantial number of small entities
SPP	Southwest Power Pool
TDD	Technical Development Document
TWPE	Toxic weighted pound equivalent
UMRA	Unfunded Mandates Reform Act
VOM	Variable O&M
WECC	Western Energy Electricity Coordinating Council
TRE	Texas Regional Reliability Entity

Executive Summary

The U.S. Environmental Protection Agency (EPA) is proposing a regulation that would revise the technology-based effluent limitations guidelines and standards (ELGs) for the steam electric power generating point source category, 40 CFR part 423, which the EPA promulgated in November 2015 (80 FR 67838). The regulatory options would revise certain best available technology (BAT) effluent limitations and pretreatment standards for existing sources (PSES) for two wastestreams: flue gas desulfurization (FGD) wastewater and bottom ash transport water.

This proposed action is an economically significant deregulatory action that was submitted to the Office for Management and Budget (OMB) for interagency review. This Regulatory Impact Analysis (RIA) presents an assessment of the compliance costs and impacts associated with this action and present analyses to meet various statutory and Executive Order requirements. The accompanying Benefit Cost Analysis (BCA) document presents social costs and benefits of the action, consistent with Executive Orders 12866, 13563, and 13771.

Regulatory Options

The EPA analyzed four different regulatory options (Table ES-1). The baseline for the analyses reflects 2015 ELG requirements (in absence of any new final EPA action). The Agency calculated the difference between the baseline and the regulatory options to determine the net incremental effect (as positive or negative change) of the regulatory options. The EPA proposes to establish BAT effluent limitations based on the technologies described in Option 2.

Table ES-1: Regulatory Options

Wastestream	Subcategory	Technology Basis for BAT/PSES Regulatory Options[a]				
		2015 Rule (Baseline)	**Option 1**	**Option 2**	**Option 3**	**Option 4**
FGD Wastewater	NA[b]	Chemical Precipitation + Biological Treatment	Chemical Precipitation	Chemical Precipitation + LRTR Biological Treatment	Chemical Precipitation + LRTR Biological Treatment	Membrane Filtration
	High FGD Flow Facilities: Plant-level scrubber purge flow >4 MGD	NS	NS	Chemical Precipitation	Chemical Precipitation	Chemical Precipitation
	Low Utilization Boilers: All units have net generation ≤ 876,000 MWh	NS	NS	Chemical Precipitation	NS	NS
	Boilers retiring by 2028[c]	NS	Surface Impoundment	Surface Impoundment	Surface Impoundment	Surface Impoundment
FGD Wastewater Voluntary Incentives Program (Direct Dischargers Only)		Chemical Precipitation + Evaporation	Membrane Filtration	Membrane Filtration	Membrane Filtration	NA

Table ES-1: Regulatory Options

Wastestream	Subcategory	Technology Basis for BAT/PSES Regulatory Options[a]				
		2015 Rule (Baseline)	Option 1	Option 2	Option 3	Option 4
Bottom Ash Transport Water	NA[b]	Dry Handling / Closed loop	Dry Handling or High Recycle Rate Systems	Dry Handling or High Recycle Rate Systems	Dry Handling or High Recycle Rate Systems	Dry Handling or High Recycle Rate Systems
	Low Utilization Boilers: All units have net generation ≤ 876,000 MWh	NS	NS	Surface Impoundment + BMP Plan	NS	NS
	Boilers retiring by 2028	NS	Surface Impoundment	Surface Impoundment	Surface Impoundment	Surface Impoundment

Abbreviations: BMP = Best Management Practice; LRTR = Low Hydraulic Residence Time; NS = Not subcategorized; NA = Not applicable

a. See *Supplemental TDD* for a description of these technologies

b. The 2015 rule subcategorized units with nameplate capacity 50 MW or less and the EPA is not revising requirements for these units in this proposal.

Source: U.S. EPA, 2019

Annualized Compliance Costs

The EPA estimates that the four options provide compliance cost savings when compared to the baseline (Table ES-2). On an *after-tax* basis, the cost savings when compared to baseline compliance costs range from $26.4 million to $146.5 million, depending on the option. The proposed option, Option 2, provides the greatest cost savings, followed by Option 1, Option 3, and finally Option 4.

Table ES-2: Estimated Incremental Annualized After-tax Compliance Costs (in millions, 2018$, discounted at 2020 using 7 percent)

Regulatory Option	Net Capital Technology	Net Other Initial One-Time[a]	Net Total O&M	Net Total Costs
Option 1	-$97.0	$0.0	-$39.6	-$136.6
Option 2	-$104.0	$0.1	-$42.5	-$146.5
Option 3	-$86.8	$0.0	-$19.0	-$105.9
Option 4	-$60.4	$0.0	$34.0	-$26.4

Source: U.S. EPA Analysis, 2019

Impacts on Steam Electric Industry and Electricity Market

The EPA assessed the impacts of the regulatory options on the steam electric industry and the electricity market in two ways:

1. A screening-level assessment reflecting historical characteristics of steam electric power plants and with assignment of estimated compliance costs to the plants and their owners. Specifically, the EPA calculated cost-to-revenue ratios for individual steam electric power plants and for domestic parent-entities owning these plants to assess the relative impact of compliance outlays. Overall, this screening-level analysis shows that few entities are likely to experience significant

changes in compliance costs compared to revenues, and all four regulatory options further lessen economic impacts to these entities. See *Chapter 4* for details.

2. A broader electricity market-level analysis using the Integrated Planning Model (IPM), which provides a more comprehensive indication of the economic impacts of the regulatory options, including an assessment of changes in in the operating characteristics of steam electric power plants and other electricity generators resulting from changes in electricity markets and the regulatory options. The EPA conducted these IPM analyses on regulatory options 2 and 4 to capture the range of potential impacts of this proposal.

Results across these analyses show that the proposed Option 2 would have small impacts on the steam electric power plants, on the entities that own these plants, and on the electricity market as a whole. For example, IPM results for the market show net changes in total generation capacity or generation costs of less than 0.5 percent across economic measures for Option 2 in the model year 2030 after implementation of the revised ELGs (see Table ES-3). The proposed option results in a small projected increase in generation capacity (0.1 percent of the baseline), including net avoided early retirements of coal-fired electricity generating units. Results for steam electric power plants (in Table ES-4), also show small impacts, with a net increase in total capacity under Option 2 when compared to the baseline of approximately 0.9 percent, and net increases in total generation by steam electric power plants of 0.3 percent for Option 2. These findings suggest that Option 2 in this proposal would have small economic consequences for the steam electric power generating industry and the electricity market overall. Looking specifically at plants with estimated compliance costs, the results for Option 2 shows no change, or less than a one percent reduction or one percent increase in capacity utilization, electricity generation, or variable production costs, providing further support the conclusion that the effects of Option 2 in this proposed rule on the steam electric industry will be small. See *Chapter 5* for details of these analyses, including results by region and for different model years. Results for Option 4 show greater impacts, but they are still considered small.

Table ES-3: Modeled Impact of Regulatory Options on National Electricity Market at the Year 2030

Economic Measures (all dollar values in 2018$)	Baseline Value	Option 2			Option 4		
		Value	Difference	% Change	Value	Difference	% Change
Total Domestic Capacity (GW)	1,142	1,143	0.6	0.1%	$1,144	1.4	0.1%
Existing			1.5	0.1%		2.0	0.2%
New Additions			-0.9	-0.1%		-0.6	-0.1%
Early Retirements			-1.5	-0.1%		-2.0	-0.2%
Generation (TWh)	4,286	4,287	0.1	0.0%	4,287	0.2	0.0%
Costs ($Millions)	$156,921	$156,781	-$140	-0.1%	$156,925	$4	0.0%
Fuel Cost	$69,971	$70,028	$57	0.1%	$69,991	$20	0.0%
Variable O&M	$10,261	$10,263	$2	0.0%	$10,307	$47	0.5%
Fixed O&M	$52,916	$52,834	-$82	-0.2%	$52,933	$17	0.0%
Capital Cost	$23,774	$23,657	-$117	-0.5%	$23,694	-$79	-0.3%
Variable Production Cost ($/MWh)	$18.72	$18.73	$0.01	0.1%	$18.73	$0.01	0.1%
CO2 Emissions (Million Metric Tons)	1,581	1,585	3.9	0.2%	1,582	1.2	0.1%
Mercury Emissions (Tons)	4	4	0.0	0.4%	4	0.0	0.1%
NOx Emissions (Million Tons)	1	1	0.0	0.5%	1	0.0	0.1%

Table ES-3: Modeled Impact of Regulatory Options on National Electricity Market at the Year 2030

Economic Measures (all dollar values in 2018$)	Baseline Value	Option 2			Option 4		
		Value	Difference	% Change	Value	Difference	% Change
SO2 Emissions (Million Tons)	1	1	0.0	0.6%	1	0.0	0.2%
HCL Emissions (Million Tons)	0	0	0.0	0.5%	0	0.0	0.1%

Source: U.S. EPA Analysis, 2019

Table ES-4: Impact of Regulatory Options on Facilities in the Steam Electric Power Generating Point Source Category, as a Group, at the Year 2030

Economic Measures (all dollar values in 2018$)	Baseline Value	Option 2			Option 4		
		Value	Difference	% Change	Value	Difference	% Change
Total Domestic Capacity (MW)	336,872	339,752	2,880	0.9%	340,066	3,194	0.9%
Early Retirements - Number of Plants	79	79	0	0.0%	78	-1	-1.3%
Full & Partial Retirements - Capacity (MW)	58,192	55,312	-2,880	-4.9%	54,998	-3,194	-5.5%
Generation (GWh)	1,570,513	1,575,189	4,676	0.3%	1,571,747	1,235	0.1%
Costs ($Millions)	$60,298	$60,397	$98	0.2%	$60,401	$103	0.2%
Fuel Cost	$34,842	$34,976	$134	0.4%	$34,893	$51	0.1%
Variable O&M	$5,987	$5,999	$12	0.2%	$6,040	$52	0.9%
Fixed O&M	$19,165	$19,117	-$48	-0.3%	$19,166	$1	0.0%
Capital Cost	$304	$304	$0	0.1%	$303	-$1	-0.3%
Variable Production Cost ($/MWh)	$26.00	$26.01	$0.02	0.1%	$26.04	$0.05	0.2%

Source: U.S. EPA Analysis, 2019

Potential Impacts on Employment

In addition to addressing the costs and impacts of the regulatory options, the EPA discusses the potential impacts of this rulemaking on employment in *Chapter 6*. Overall, any job impacts of the regulatory options, both positive and negative, are estimated to be small.

Potential Electricity Price Effects

The EPA also assessed the potential impacts of the regulatory options on electricity prices, assuming full cost pass-through of compliance costs in electricity prices. The Agency conducted this analysis in two parts: (1) an assessment of the potential annual changes in electricity costs per MWh of total electricity sales; and (2) an assessment of the potential annual changes in household electricity costs. *Chapter 7* details these analyses.

Changes in costs per MWh of total electricity sales are small for all regulatory options; the maximum difference in price effect is a fraction of a cent per kWh. Overall across the United States, Option 2 results in the highest cost savings of 0.005¢ per kWh, and Option 4 results in the lowest cost savings of 0.001¢ per kWh.

On the national level, cost savings relative to household electricity costs are greatest on average under Option 2, with average cost savings of $0.49 per year per household; by region, cost savings range between $0.03 and $1.20 per year per household. The least cost savings occur under Option 4, with average cost savings per residential household of $0.07 per year; by region, cost savings range between $0.01 and $0.21 per year. The average incremental annual cost savings per residential household is greatest in the Southeastern Electric Reliability Council (SERC) region and the least in Western Energy Coordinating Council (WECC) region under all options.

Potential Impacts on Small Entities

In accordance with the Regulatory Flexibility Act (RFA) requirements, the EPA assessed whether the regulatory options would have "a significant impact on a substantial number of small entities" (SISNOSE). The analysis is detailed in *Chapter 8.*

This involved analyzing the baseline, analyzing the four regulatory options, and then drawing conclusions on the basis of the differences between the options and the baseline. Given net cost savings described earlier, the proposed rule may also lessen impacts on small entities. The EPA estimates that 79 to 127 small entities own steam electric power plants that may incur compliance costs under the proposed option. In the baseline, the EPA estimates that 4 small entities owning steam electric power plants would incur costs exceeding one percent of revenue, and 2 of the 4 would incur costs exceeding three percent of revenue. Under Option 2, relative to the baseline 2 fewer small entities would incur costs exceeding one percent of revenue, and 1 fewer small entity would incur costs exceeding three percent of revenue. Under the other three options, 1 fewer small entity would incur costs exceeding one percent of revenue, and no change is estimated for the number of plants incurring costs greater than three percent of revenue. This screening-level analysis suggests that the proposed option is estimated to reduce this impact further by providing cost savings to many small entities.

Unfunded Mandate Reform Act

Under Title II of the Unfunded Mandates Reform Act (UMRA) of 1995 section 202, the EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with "Federal mandates" that might result in expenditures by State, local, and Tribal governments, in the aggregate, or by the private sector, of $100 million (adjusted annually for inflation) or more in any one year (*i.e.*, $160 million in 2018 dollars). As discussed in *Chapter 9*, the EPA estimates that the proposed option would not result in incremental expenditures of at least $160 million for State and local government entities, in the aggregate, or for the private sector in any one year. In fact, Option 2 would provide net cost savings when compared to the baseline. Furthermore, neither permitted plants nor permitting authorities are estimated to incur significant additional administrative costs as the result of the regulatory options. Consistent with Section 205 of UMRA, the EPA presents four regulatory options which would all reduce impacts to governments and the private sector. The proposed option (Option 2) is the least costly option presented, and thus would result in the lowest impacts to governments and the private sector. Furthermore, several government and private sector plants would likely fall into subcategories within Option 2 which would provide additional flexibility. Finally, the implementation period built into Option 2 is another way for permit writers to consider the site-specific needs of steam electric power plants.

Other Administrative Requirements

The EPA conducted analyses to address other administrative requirements. Key findings, which are discussed further in *Chapter 10*, include:

- **Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review:** Pursuant to the terms of Executive Order 12866, this action is an "economically significant regulatory action" because the action is likely to have an annual effect on the economy of $100 million or more, although the direction of the effect is estimated to be a reduction in costs when compared to the baseline. As such, the action is subject to review by the OMB under Executive Orders 12866 and 13563. Any changes made in response to OMB suggestions or recommendations will be documented in the docket for this action. The EPA prepared an analysis of the potential benefits and costs associated with this action; this analysis is detailed in Chapter 13 of the BCA document (U.S. EPA, 2019b).

- **Executive Order 13771: Reducing Regulation and Controlling Regulatory Costs:** The proposed rule, if finalized, is expected to be a deregulatory action under E.O. 13771, Reducing Regulation and Controlling Regulatory Costs. See Chapter 12 in the BCA document (U.S. EPA, 2019b) for details on the time profile of costs and annualized discounted costs.

- **Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use:** The EPA's analyses show that the proposed Option 2 would not have a significant adverse effect at a national or regional level under Executive Order 13211. Specifically, the Agency's analyses found that Option 2 would not reduce electricity production in excess of 1 billion kilowatt hours per year or in excess of 500 megawatts of installed capacity under either of the options analyzed, nor would the option increase U.S. dependence on foreign supply of energy.

- **Executive Order 12898: Federal Actions to Address Environmental Justice (EJ) in Minority Populations and Low-Income Populations**: The EPA examined whether the benefits from the regulatory options may be differentially distributed among population subgroups in the affected areas. As described in *Chapter 10* and detailed in Chapter 14 of the BCA document (U.S. EPA, 2019b), the EPA determined that the majority of impacted communities at the census block, county, and tribal area levels are poorer and more minority than state averages. Therefore, the regulatory options could benefit or harm populations with EJ concerns depending on each option's pollutant exposure potential. The EPA determined that the regulatory options will would not deny communities from the benefits of environmental improvements estimated to result from compliance with the more stringent effluent limits, but the options may disproportionally affect communities in cases where the proposed rule may result in small increases pollutant exposure.

- **Executive Order 13045: Protection of Children from Environmental Health Risks and Safety Risks:** As described in *Chapter 10* and detailed in the BCA document (U.S. EPA, 2019b), the EPA identified several ways in which Option 2 could affect children, including by potentially increasing health risk from exposure to pollutants present in steam electric power plant discharges. However, the EPA's analysis of the environmental health risks or safety risks addressed by this action do not present a *disproportionate* risk to children.

1 Introduction

1.1 Background

The EPA is proposing a regulation that would revise the technology-based effluent limitations guidelines and standards (ELGs) for the steam electric power generating point source category, 40 CFR part 423, which the EPA promulgated in November 2015 (80 FR 67838). The regulatory options would revise certain BAT effluent limitations and pretreatment standards for existing sources for two wastestreams: bottom ash transport water and flue gas desulfurization (FGD) wastewater.

This document describes the Agency's analysis of the costs and economic impacts of the proposed regulatory option and the other options that were evaluated by EPA but are not proposed for the ELG. It also provides information pertinent to meeting several legislative and administrative requirements.

This document complements and builds on information presented separately in other reports, including:

- *Supplemental Technical Development Document for the Reconsideration of the Effluent Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (Supplemental TDD) (U.S. EPA, 2019a). The *Supplemental TDD* provides background on the regulatory options; applicability and summary of the regulatory options; industry description; wastewater characterization and identifying pollutants; and treatment technologies and pollution prevention techniques. It also documents the EPA's engineering analyses to support the regulatory options including facility specific compliance cost estimates, pollutant loadings, and non-water quality impact assessment.

- *Benefit and Cost Analysis for Proposed Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (BCA) (U.S. EPA, 2019b). The *BCA* summarizes the societal benefits and costs estimated to result from implementation of the regulatory options.

- *Supplemental Environmental Assessment for the Reconsideration of the Effluent Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (Supplemental EA) (U.S. EPA, 2019c). The *Supplemental EA* summarizes the environmental and human health improvements that are estimated to result from implementation of the regulatory options.

The proposed revisions to the ELGs for the Steam Electric Power Generating Point Source Category are based on data generated or obtained in accordance with EPA's Quality Policy and Information Quality Guidelines. The EPA's quality assurance (QA) and quality control (QC) activities for this rulemaking include the development, approval and implementation of Quality Assurance Project Plans for the use of environmental data generated or collected from all sampling and analyses, existing databases and literature searches, and for the development of any models which used environmental data. Unless otherwise stated within this document, the data used and associated data analyses were evaluated as described in these quality assurance documents to ensure they are of known and documented quality, meet the EPA's requirements for objectivity, integrity and utility, and are appropriate for the intended use.

1.2 Overview of the Costs and Economic Impacts Analysis

This section describes the key components of the analysis framework. The Agency's analysis generally follows the methodology the EPA previously used to analyze the ELGs the Agency promulgated in 2015 (see RIA document at U.S. EPA (2015b). *Appendix A* describes the principal changes to the regulatory options analysis, as compared to the 2015 rule analysis. These changes include:

- Updating the information on the control and treatment technologies and associated costs for bottom ash transport water and FGD wastewater (see *Supplemental TDD* for details).
- Updating the universe of steam electric power plants and their wastestreams to account for major changes such as additional retirements, fuel conversions, ash handling conversions, wastewater treatment updates and updated information on capacity utilization.
- Using the most recent Integrated Planning Model platform (IPM v6 vs. IPM v5.13) to evaluate the impact of the ELG on the electricity markets. IPM v6 incorporates the effects of existing regulations and programs or estimated to be in effect by the time the regulatory options are implemented. See additional discussion in *Chapter 5: Assessment of the Impact of the Regulatory Options in the Context of National Electricity Markets*.
- Updating the analysis year (2020 vs. 2015) and dollar year (2018 dollars vs. 2013 dollars).
- Updating electricity generation, sales, and electricity prices based on the most current data from the Energy Information Administration (EIA) (*e.g.*, 2016 vs. 2012).
- Updating the SBA small business size thresholds (October 2017 standards vs. July 2014 standards), updating information about the entities that own steam electric generating units, based on EIA data, and recategorizing these entities as small or large.

1.2.1 Main Regulatory Options Presented in the Proposed Rule

The EPA is proposing one regulatory option, described further below. As part of its rule, EPA evaluated three additional options, which are also presented in the preamble. Table 1-1 summarizes the four regulatory options evaluated for the proposed rule. The table also shows the technology basis for the 2015 rule, which as discussed in *Section 1.2.2* is used as baseline for the analysis. All options evaluated by EPA include the same technology basis for bottom ash transport water. In general, each succeeding option from Option 1 to 4 would achieve more reduction in FGD wastewater pollutant discharges.

Table 1-1: Regulatory Options

Wastestream	Subcategory	Technology Basis for BAT/PSES Regulatory Options[a]				
		2015 Rule (Baseline)	**Option 1**	**Option 2**	**Option 3**	**Option 4**
FGD Wastewater	NA[b]	Chemical Precipitation + HRTR Biological Treatment	Chemical Precipitation	Chemical Precipitation + LRTR Biological Treatment	Chemical Precipitation + LRTR Biological Treatment	Membrane Filtration
	High FGD Flow Facilities: Plant-level scrubber purge flow >4 MGD	NS	NS	Chemical Precipitation	Chemical Precipitation	Chemical Precipitation
	Low Utilization Boilers: All units have net generation ≤ 876,000 MWh	NS	NS	Chemical Precipitation	NS	NS
	Boilers retiring by 2028[c]	NS	Surface Impoundment	Surface Impoundment	Surface Impoundment	Surface Impoundment
FGD Wastewater Voluntary Incentives Program (Direct Dischargers Only)		Chemical Precipitation + Evaporation	Membrane Filtration	Membrane Filtration	Membrane Filtration	NA
Bottom Ash Transport Water	NA[b]	Dry Handling / Closed loop	Dry Handling or High Recycle Rate Systems	Dry Handling or High Recycle Rate Systems	Dry Handling or High Recycle Rate Systems	Dry Handling or High Recycle Rate Systems
	Low Utilization Boilers: All units have net generation ≤ 876,000 MWh	NS	NS	Surface Impoundment + BMP Plan	NS	NS
	Boilers retiring by 2028	NS	Surface Impoundment	Surface Impoundment	Surface Impoundment	Surface Impoundment

Abbreviations: BMP = Best Management Practice; HRTR = High Hydraulic Residence Time; LRTR = Low Hydraulic Residence Time; NS = Not subcategorized; NA = Not applicable

a. See *Supplemental TDD* for a description of these technologies

b. The 2015 rule subcategorized units with nameplate capacity 50 MW or less and the EPA is not revising requirements for these units in this proposal.

Source: U.S. EPA Analysis, 2019

1.2.2 Baseline

The baseline for the analyses supporting this proposed rule reflects the ELG requirements from the 2015 rule as well as the September 2017 postponement rule which delayed the earliest compliance date for the ELGs applicable to FGD wastewater and bottom ash transport water (in absence of any new final EPA action). The Agency estimated and presents in this report the compliance costs that plants could incur under both this baseline and each of the four regulatory options presented in Table 1-1. The Agency calculated the difference between the baseline and the regulatory options to determine the net effect (as positive or negative change) of the regulatory options.

The EPA updated baseline information to incorporate major changes in the universe and operational characteristics of steam electric power plants such as additional retirements and fuel conversions since the analysis of the 2015 rule detailed in U.S. EPA (2015b). The EPA also incorporated updated information on the technologies and other controls that plants employ. The current analysis focuses only on the two wastestreams addressed in the regulatory options: bottom ash transport water and FGD wastewater. Because of these updates, the costs and economic impacts of the baseline presented in this document are estimated to differ from those presented in the RIA document for the 2015 rule (U.S. EPA, 2015b), and better reflect actual costs of the 2015 rule today.

Unless otherwise specified, references to the 2015 rule baseline in the remainder of this document includes both the technical requirements of the 2015 rule as well as the timing effects of the 2017 applicability date rule.

1.2.3 Cost and Economic Analysis Requirements under the Clean Water Act

The EPA's effluent limitations guidelines and standards for the steam electric industry are promulgated under the authority of the CWA Sections 301, 304, 306, 307, 308, 402, and 501 (33 U.S.C. 1311, 1314, 1316, 1317, 1318, 1342, and 1361). These CWA sections require the EPA Administrator to publish limitations and guidelines for controlling industrial effluent discharges consistent with the overall CWA objective to "restore and maintain the chemical, physical, and biological integrity of the Nation's waters" (33 U.S.C. 1251(a)). In establishing national effluent guidelines and pretreatment standards for pollutants, the EPA considers the performance of control and treatment technologies and the cost and/or "economic achievability" of the controls.

The EPA analyzed economic achievability; the cost and economic impact analysis for this rulemaking also focuses on understanding the magnitude and distribution of compliance cost savings across the industry, and the broader market impacts.[1] This report also documents analyses required under other legislative (*e.g.*, Regulatory Flexibility Act, Unfunded Mandates Reform Act) and administrative requirements (*e.g.*, Executive Order 12866: Regulatory Planning and Review).

[1] Since there have been many changes to the industry since the 2015 rule, the EPA also evaluates impacts in light of these changes to confirm its findings that the costs are economically achievable.

1.2.4 Analyses in Support of the Regulatory Options and Report Organization

This document discusses the following analyses the EPA performed in support of the regulatory options as compared to the baseline:

- **Overview of the steam electric industry** (Chapter 2), which focuses on changes to the industry since the 2015 rule.

- **Compliance cost assessment** (Chapter 3), which describes the cost components and calculates the industry-wide compliance costs for the baseline and regulatory options and estimates the incremental costs attributable to the regulatory options.

- **Cost and economic impact screening analyses** (Chapter 4), which evaluates the incremental impacts of compliance on plants and their owning entities on a cost-to-revenue basis.

- **Assessment of impacts in the context of national electricity markets** (Chapter 5), which analyzes the impacts of the regulatory options using the Integrated Planning Model (IPM) and provides insight into the incremental effects of the regulatory options on the steam electric power generating industry and on national electricity markets, relative to the baseline.

- **Analysis of employment effects** (Chapter 6), which assesses national-level changes in employment in the steam electric industry, relative to the baseline.

- **Assessment of potential electricity price effects** (Chapter 7), which looks at the incremental impacts of compliance in terms of increased electricity prices for households and for other consumers of electricity.

- **Regulatory Flexibility Act (RFA) analysis** (Chapter 8) which assesses the change in impact of the rule on small entities on the basis of a revenue test, *i.e.*, cost-to-revenue comparison.

- **Unfunded Mandates Reform Act (UMRA) analysis** (Chapter 9) which assesses the change in impact on government entities, in terms of (1) compliance costs to government-owned plants and (2) administrative costs to governments implementing the rule. The UMRA analysis also compares the impacts to small governments with those of large governments and small private entities.

- **Analyses to address other administrative requirements** (Chapter 10), such as Executive Order 13211, which requires the EPA to determine if this action would have a significant effect on energy supply, distribution, or use.

These analyses generally follow the same methodology used by the EPA for the analysis of the 2015 rule and the discussion follows a presentation very similar to that in the RIA document for the 2015 rulemaking (U.S. EPA, 2015b).

Chapter 11 provides detailed information on sources cited in the text and three appendices provide supporting information:

- *Appendix A: Summary of Changes to Costs and Economic Impact Analysis* lists the principal changes the EPA made to its costs and economic impact analysis for the regulatory options, relative to the methodology used to analyze the 2015 rule.

- *Appendix B: Cost Effectiveness* describes the EPA's analysis of the cost-effectiveness of the regulatory options.

2 Overview of the Steam Electric Industry

This section provides a general description of the steam electric industry, focusing on changes to the universe of plants and entities that own the plants as compared to the profile used for the 2015 rule (U.S. EPA, 2015b). It also discusses the regulations applicable to the universe of plants that may be affected by the regulatory options.

2.1 Steam Electric Industry

The proposed option would revise BAT limitations and pretreatment standards for bottom ash transport water and FGD wastewater for existing sources in the steam electric industry. The Steam Electric Power Generating Point Source Category covers “discharges resulting from the operation of a generating unit by an establishment whose generation of electricity is the predominant source of revenue or principal reason for operation, and whose generation of electricity results primarily from a process utilizing fossil-type fuel (coal, oil, or gas), fuel derived from fossil fuel (e.g., petroleum coke, synthesis gas), or nuclear fuel in conjunction with a thermal cycle employing the steam water system as the thermodynamic medium.” (40 CFR 423.10)

The EPA had identified 1,080 steam electric power plants – including plants that operate coal, oil, gas, and nuclear generating units – and used this universe in its analysis of the 2015 rule (U.S EPA, 2015b). Review of more recent data revealed that some of the plants the EPA surveyed in 2010[2] have since retired their coal steam units, converted to different fuels, or made other changes that affect discharge characteristics. The *Supplemental TDD* describes the changes in the steam electric industry population since the 2015 rule analysis, including retirements, fuel conversions, ash handling conversions, wastewater treatment updates, and updated information on capacity utilization (U.S. EPA, 2019a).

The EPA adjusted the 2015 universe to remove coal steam plants that would no longer fit the definition of the Steam Electric Power Generating point source category. As a result of these adjustments, the EPA estimates that there are 951 plants in the steam electric power generating industry. As presented in Table 2-1 (next page), the 951 steam electric power plants represent approximately 10 percent of the total number of plants in the power generation sector, but represent approximately 59 percent of the national total electric generating capacity with 695,729 MW.

Of the estimated 951 steam electric power plants in the universe, only a subset may incur compliance costs under the proposed option: those coal fired power plants that discharge bottom ash transport water or FGD wastewater. As presented in Table 2-1, the EPA estimated that 114 plants may incur non-zero compliance costs under either the baseline or any of the four regulatory options; these plants represent 1.2 percent of the total plants reported by EIA in 2016 and 13.5 percent of the total generating capacity.

[2] See *Questionnaire for the Steam Electric Power Generating Effluent Guidelines* (Steam Electric Survey; U.S. EPA, 2010b)

Table 2-1: Steam Electric Industry Share of Total Electric Power Generation Plants and Capacity in 2016					
		Steam Electric Industry[b]		**Plants with Non-Zero Compliance Costs for Baseline or Regulatory Options[c]**	
	Total[a]	**Number**	**% of Total**	**Number**	**% of Total**
Plants	9,711	951	9.8%	114	1.2%
Capacity (MW)	1,177,183	695,729	59.1%	158,845	13.5%

a. Data for total electric power generation industry are from the 2016 EIA-860 database (EIA, 2017a) and 2016 EIA-861 database (EIA, 2017b).

b. Steam electric power plant count and capacity were calculated on a sample-weighted basis.

c. See Chapter 3 for details on compliance cost estimates.

Source: U.S. EPA Analysis, 2019; EIA, 2017a; EIA, 2017b.

The following sections present information on ownership, physical, geographic and operating characteristics of steam electric power plants.

2.1.1 Owner Type and Size

Entities that own electric power plants can be divided into seven major ownership categories: investor-owned utilities, nonutilities, federally-owned utilities, State-owned utilities, municipalities, rural electric cooperatives, and other political subdivisions. These categories are important because the EPA has to assess the impact of the proposed option on State, local, and tribal governments in accordance with UMRA of 1995 (see *Chapter 9*: *Unfunded Mandates Reform Act (UMRA) Analysis*).

Table 2-2 reports the number of parent entities, plants, and capacity by ownership type for the 951 steam electric power plants (for details on determination of parent entities for steam electric power plants, see *Chapter 4*: *Cost and Economic Impact Screening Analyses*). The majority of steam electric power plants (54 percent of all steam electric power plants) are owned by investor-owned utilities, while nonutilities make up the second largest category (21 percent of all steam electric power plants). In terms of steam electric capacity, investor-owned utilities account for the largest share (67 percent) of total steam electric capacity.

Table 2-2: Existing Steam Electric Power Plants, Their Parent Entities, and Capacity by Ownership Type, 2016								
	Parent Entities [a,b,c]				**Plants [a,b,d]**		**Capacity (MW) [a,d]**	
	Lower Bound		**Upper Bound**					
Ownership Type	**Number**	**% of Total**	**Number**	**% of Total**	**Number[c]**	**% of Total**	**Number[c]**	**% of Total**
Cooperative	28	11.5%	50	10.5%	64	6.7%	38,416	5.5%
Federal	1	0.4%	3	0.7%	20	2.1%	27,022	3.9%
Investor-owned	69	28.4%	157	32.8%	509	53.5%	465,410	66.9%
Municipality	59	24.3%	94	19.8%	123	12.9%	45,934	6.6%
Nonutility	74	30.5%	150	31.4%	198	20.8%	87,639	12.6%
Other Political Subdivisions	10	4.1%	21	4.5%	34	3.5%	26,525	3.8%
State	2	0.8%	2	0.4%	4	0.4%	4,784	0.7%

Table 2-2: Existing Steam Electric Power Plants, Their Parent Entities, and Capacity by Ownership Type, 2016

Ownership Type	Parent Entities [a,b,c]				Plants [a,b,d]		Capacity (MW) [a,d]	
	Lower Bound		Upper Bound					
	Number	% of Total	Number	% of Total	Number[c]	% of Total	Number[c]	% of Total
Total	**243**	**100.0%**	**478**	**100.0%**	**951**	**100.0%**	**695,729**	**100.0%**

a. Numbers may not add up to totals due to independent rounding.

b. Ownership information on steam electric power plants and their parent entities is based on information gathered through the Steam Electric Survey (U.S. EPA, 2010b) and additional research of publicly available information.

c. Parent entity counts are calculated on a sample-weighted basis and represent the lower and upper bound estimates of the number of entities owning steam electric power plants. For details see *Chapter 4*.

d. Steam electric power plant count and capacity were calculated on a sample-weighted basis. For details on sample weights, see *Supplemental TDD*.

Source: U.S. EPA Analysis, 2019; EIA, 2017a

The EPA estimates that between 27 percent and 33 percent of entities owning steam electric power plants are small (Table 2-3), according to Small Business Administration (SBA) (2017) business size criteria. By definition, states and the federal government are considered large entities.

The size distribution of parent entities owning steam electric power plants varies by ownership type. Under the lower bound estimate, the lowest share of small entities is in the other political subdivision[3] category (10 percent), while cooperatives and small municipalities make up the largest share of small entities (75 percent and 49 percent, respectively). The pattern is similar under the upper bound estimate, but small entities representing 5 percent of other political subdivision entities, 72 percent of cooperatives, and 39 percent of municipalities.

The EPA estimates that out of 951 steam electric power plants, 139 (15 percent) are owned by small entities (Table 2-4). Cooperatives own the largest share (30 percent) of steam electric power plants owned by small entities, while investor-owned utilities, nonutilities, municipalities, and other political subdivisions own the remaining 70 percent. For a detailed discussion of the identification and size determination of parent entities of steam electric power plants, see *Chapter 4* and *Chapter 8*.

Table 2-3: Parent Entities of Steam Electric Power Plants by Ownership Type and Size (assuming two different ownership cases)[a,b]

Ownership Type	Lower bound estimate of number of entities owning steam electric power plants				Upper bound estimate of number of entities owning steam electric power plants			
	Small	Large	Total	% Small	Small	Large	Total	% Small
Cooperative	21	7	28	75.0%	36	14	50	72.2%
Federal	0	1	1	0.0%	0	3	3	0.0%
Investor-owned	9	60	69	13.0%	20	136	157	13.0%
Municipality	29	30	59	49.2%	37	57	94	39.1%
Nonutility	19	55	74	25.7%	33	117	150	22.0%
Other Political Subdivision	1	9	10	10.0%	1	20	21	4.7%

3 Other political subdivisions include public power districts and irrigation projects.

Table 2-3: Parent Entities of Steam Electric Power Plants by Ownership Type and Size (assuming two different ownership cases)[a,b]

Ownership Type	Lower bound estimate of number of entities owning steam electric power plants				Upper bound estimate of number of entities owning steam electric power plants			
	Small	Large	Total	% Small	Small	Large	Total	% Small
State	0	2	2	0.0%	0	2	2	0.0%
Total	**79**	**164**	**243**	**32.5%**	**127**	**350**	**478**	**26.6%**

a. Numbers may not add up to totals due to independent rounding.

b. For details on estimates of the number of majority owners of steam electric power plants see *Chapter 4* and *Chapter 8*.

Source: U.S. EPA Analysis, 2019

Table 2-4: Steam Electric Power Plants by Ownership Type and Size

Ownership Type	Number of Steam Electric Power Plants[a,b,c]			
	Small	Large	Total	% Small
Cooperative	41	23	64	64.2%
Federal	0	20	20	0.0%
Investor-owned	22	487	509	4.4%
Municipality	37	86	123	30.1%
Nonutility	38	160	198	19.2%
Other Political Subdivisions	1	33	34	3.0%
State	0	4	4	0.0%
Total	**139**	**811**	**951**	**14.7%**

a. Numbers may not sum to totals due to independent rounding.

b. Plant counts are sample-weighted estimates.

c. Plant size was determined based on the size of majority owners. In case of multiple owners with equal ownership shares, a plant was assumed to be small if it is owned by at least one small entity.

Source: U.S. EPA Analysis, 2019

2.1.2 Geographic Distribution of Steam Electric Power Plants

The U.S. bulk power system is composed of three major networks, or power grids, subdivided into several smaller North American Electric Reliability Corporation (NERC) regions:

- The *Eastern Interconnected System* covers the largest portion of the United States, from the eastern end of the Rocky Mountains and the northern borders to the Gulf of Mexico states (including parts of northern Texas) on to the Atlantic seaboard.

- The *Western Interconnected System* covers nearly all of areas west of the Rocky Mountains, including the Southwest.

- The *Texas Interconnected System*, the smallest of the three major networks, covers the majority of Texas.

The Texas system is not connected with the other two systems, while the other two have limited interconnection to each other. The Eastern and Western systems are integrated with, or have links to, the Canadian grid system. The Western and Texas systems have links with Mexico.

These major networks contain extra-high voltage connections that allow for power transmission from one part of the network to another. Wholesale transactions can take place within these networks to reduce power costs, increase supply options, and ensure system reliability.

NERC is responsible for the overall reliability, planning, and coordination of the power grids. An independent, not-for-profit organization, it has regulatory authority for ensuring electric reliability in the United States, under the oversight of FERC. NERC is organized into seven regional entities that cover the 48 contiguous States, and two affiliated councils that cover Hawaii, part of Alaska, and portions of Canada and Mexico.[4] These regional organizations are responsible for the overall coordination of bulk power policies that affect their regions' reliability and quality of service. Interconnection *between* the bulk power networks is limited in comparison to the degree of interconnection *within* the major bulk power systems. Further, the degree of interconnection between NERC regions even within the same bulk power network is also limited. Consequently, each NERC region deals with electricity reliability issues in its own region, based on available capacity and transmission constraints. The regional organizations also facilitate the exchange of information among member utilities in each region and between regions. Service areas of the member utilities determine the boundaries of the NERC regions. Though limited by the larger bulk power grids described above, NERC regions do not necessarily follow any State boundaries. Figure 2-1 provides a map of the NERC regions EPA used for the analysis of the regulatory options, listed in Table 2-5. The map uses the same regional breakout used for the 2015 rule analysis, which was based on the 2012 EIA data and separates out the Southwest Power Pool (SPP) region.[5]

Table 2-5: NERC regions

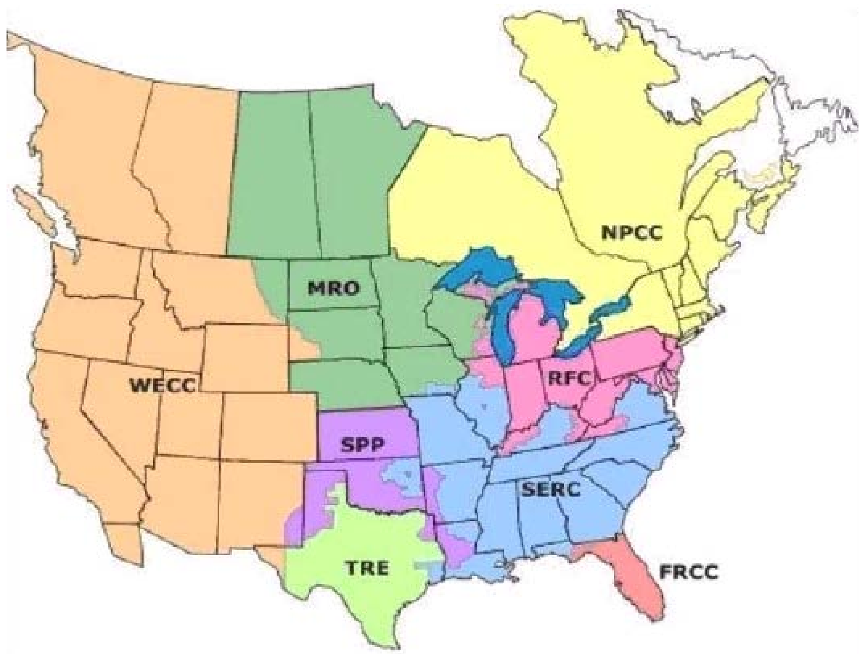
Bulk Power Network	NERC Region	NERC Entity
Eastern Interconnected System	FRCC	Florida Reliability Coordinating Council
	MRO	Midwest Reliability Organization
	NPCC	Northeast Power Coordinating Council (U.S.)
	RFC	Reliability First Corporation
	SERC	SERC Reliability Corporation
	SPP	Southwest Power Pool
Western Interconnected System	WECC	Western Energy Electricity Coordinating Council (U.S.)
Texas Interconnected System	TRE	Texas Regional Reliability Entity
	ASCC	Alaska Systems Coordinating Council
	HICC	Hawaii Coordinating Council

Source: EIA, 2012

4 Energy concerns in the States of Alaska, Hawaii, the Dominion of Puerto Rico, and the Territories of American Samoa, Guam, and the Virgin Islands are not under reliability oversight by NERC.

5 Some NERC regions have been re-defined/re-named over time. This chapter provides NERC region data by the 2012 NERC regions.

Figure 2-1: North American Electric Reliability Corporation (NERC) Regions



Note: The ASCC and HICC regions are not shown.
Source: EIA, 2012.

The evaluated options are estimated to have a different effect on profitability, electricity prices, and other impact measures across NERC regions. This is because of variations in the economic and operational characteristics of steam electric and other power plants across NERC regions, including the share of the region's electricity demand met by steam electric power plants that may incur compliance costs under the different options. Other factors include the baseline economic characteristics of the NERC regions, together with market segmentation due to limited interconnectedness among NERC regions. To assess the potential reliability impact of the regulatory options, the EPA assessed the distribution of steam electric power plants and their capacity across NERC regions.

As reported in Table 2-6, NERC regions differ in terms of both the number of steam electric power plants and their capacity. Steam electric power plants are somewhat concentrated in the RFC, SERC, and WECC regions (21 percent, 20 percent, and 17 percent, respectively); these three regions also account for a majority of the steam electric capacity in the United States (24 percent, 26 percent, and 15 percent, respectively).

Table 2-6: Steam Electric Power Plants and Capacity by NERC Region, 2012[a,b]

NERC Region	Plants		Capacity (MW)[a,b]	
	Number	% of Total	MW	% of Total
ASCC	2	0.2%	118	0.0%
FRCC	50	5.2%	53,448	7.7%
HICC	10	1.0%	750	0.1%
MRO	77	8.1%	33,921	4.9%

Table 2-6: Steam Electric Power Plants and Capacity by NERC Region, 2012[a,b]

NERC Region	Plants		Capacity (MW)[a,b]	
	Number	% of Total	MW	% of Total
NPCC	90	9.4%	35,025	5.0%
RFC	199	21.0%	163,646	23.5%
SERC	194	20.4%	181,545	26.1%
SPP	88	9.3%	60,524	8.7%
TRE	78	8.2%	61,792	8.9%
WECC	163	17.2%	104,962	15.1%
TOTAL	**951**	**100.0%**	**695,729**	**100.0%**

a. Numbers may not add up to totals due to independent rounding.

b. The numbers of plants and capacity are calculated on a sample-weighted basis.

Source: U.S. EPA Analysis, 2019; EIA, 2017a

2.1.3 Electricity Generation

Total net electricity generation in the United States for 2016 was 4,079 TWh.[6] Coal accounted for 30 percent of total electricity generation, behind natural gas (34 percent), but ahead of nuclear power (20 percent). Other energy sources accounted for comparatively smaller shares of total generation, with hydropower representing 7 percent; wind, solar and other renewable energy, 8 percent; and petroleum, 1 percent.

As presented in Table 2-7, the 5-year period of 2012 through 2016 saw total net generation increase by approximately 0.8 percent, with the 274 TWh drop in generation from coal-fueled generators (18 percent) offset by growth in generation from natural gas (154 TWh, 12.5 percent increase) and renewables (126 TWh, a 57 percent increase).

Between 2012 and 2016, the amount of electricity generated by utilities declined by 1.5 percent while that generated by nonutilities rose by 3.9 percent. Comparing 2012 and 2016 values, across all fuel-source categories, utilities generated a larger share of their electricity using natural gas (a 30 percent increase) and renewables (a 53 percent increase) even as their overall generation declined. For nonutilities, the largest percent increase in electricity generation (58 percent) occurred for renewables, whereas generation from natural gas remained largely the same.

Table 2-7: Net Generation by Energy Source and Ownership Type, 2012-2016 (TWh)

Energy Source	Utilities			Nonutilities			Total		
	2012	2016	% Change	2012	2016	% Change	2012	2016	% Change
Coal	1,146	923	-19.5%	368	317	-13.8%	1,514	1,240	-18.1%
Hydropower	249	241	-3.1%	23	18	-19.7%	271	259	-4.5%
Nuclear	395	424	7.5%	375	381	1.7%	769	805	4.7%
Petroleum	16	18	12.8%	8	6	-16.8%	23	24	3.1%
Natural Gas	505	654	29.6%	721	726	0.7%	1,226	1,380	12.6%
Other Gases	0	0	NA	12	13	7.9%	12	13	9.3%
Renewables[a]	28	43	53.0%	190	301	58.0%	218	344	57.4%

6 One terawatt-hour is 10^{12} watt-hours.

Table 2-7: Net Generation by Energy Source and Ownership Type, 2012-2016 (TWh)

	Utilities			Nonutilities			Total		
Energy Source	**2012**	**2016**	**% Change**	**2012**	**2016**	**% Change**	**2012**	**2016**	**% Change**
Other[b]	1	0	-48.3%	13	13	1.4%	14	14	-0.8%
Total	**2,339**	**2,304**	**-1.5%**	**1,709**	**1,775**	**3.9%**	**4,048**	**4,079**	**0.8%**

a. Renewables include wood, black liquor, other wood waste, municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, solar thermal, photovoltaic energy, and wind.

b. Other includes batteries, hydrogen, purchased steam, sulfur, tire-derived fuels and other miscellaneous energy sources.

Source: EIA, 2017c

2.2 Other Environmental Regulations

The RIA report for the 2015 rule described factors, such as deregulation and environmental regulations and programs, that have affected the steam electric power generating industry, and electrical power generation more generally, over the last decades. See Chapter 2 in U.S. EPA (2015b). The sections below provide updated discussions on changes to two environmental regulations since 2015.

2.2.1 Clean Power Plan (CPP) and Affordable Clean Energy (ACE) Regulations

The final 2015 CPP established carbon dioxide (CO_2) emission guidelines for fossil-fuel fired power plants based in part on shifting generation at the fleet-wide level from one type of energy source to another. On February 9, 2016, the U.S. Supreme Court stayed implementation of the CPP pending judicial review. West Virginia v. EPA, No. 15A773 (S.Ct. Feb. 9, 2016).

On June 19, 2019, the EPA issued the ACE rule, an effort to provide existing coal-fired electric utility generating units (EGUs) with achievable and realistic standards for reducing greenhouse gas emissions. This action was finalized in conjunction with two related, but separate and distinct rulemakings: (1) the repeal of the CPP, and (2) revised implementing regulations for ACE, ongoing emission guidelines, and all future emission guidelines for existing sources issued under the authority of Clean Air Act section 111(d). ACE provides states with new emission guidelines that will inform the state's development of standards of performance to reduce CO_2 emissions from existing coal-fired EGUs consistent with the EPA's role as defined in the CAA.

ACE establishes heat rate improvement (HRI), or efficiency improvement, as the best system of emissions reduction (BSER) for CO_2 from coal-fired EGUs. By employing a broad range of HRI technologies and techniques, EGUs can more efficiently generate electricity with less carbon intensity. The BSER is the best technology or other measure that has been adequately demonstrated to improve emissions performance for a specific industry or process (a "source category"). In determining the BSER, the EPA considers technical feasibility, cost, non-air quality health and environmental impacts, and energy requirements. The BSER must be applicable to, at, and on the premises of an affected facility. ACE lists six HRI "candidate technologies," as well as additional operating and maintenance (O&M) practices. For each candidate technology, the EPA has provided information regarding the degree of emission limitation achievable through application of the BSER as ranges of expected improvement and costs.

The 2015 rule analyses incorporated compliance costs associated with the 2015 CPP, resulting in, among other things, baseline retirements associated with that rule in the Integrated Planning Model (IPM). Due to the final repeal of the CPP, the analyses supporting today's proposal no longer incorporates the 2015 CPP. However, the EPA does make use of IPM version 6 to be consistent with the base case analyses done for the ACE final rule (U.S. EPA, 2019d). See additional discussion of IPM in *Chapter 5*: *Assessment of the Impact of the Regulatory Options in the Context of National Electricity Markets*. The EPA intends to perform IPM runs with the most up-to-date version of the model available for the final rule.

2.2.2 Coal Combustion Residuals Rule

On April 17, 2015, the Agency published the Disposal of Coal Combustion Residuals from Electric Utilities final rule. This rule finalized national regulations to provide a comprehensive set of requirements for the safe disposal of CCRs, commonly known as coal ash, from coal-fired power plants. The final CCR rule was the culmination of extensive study on the effects of coal ash on the environment and public health. The rule established technical requirements for CCR landfills and surface impoundments under subtitle D of the Resource Conservation and Recovery Act (RCRA), the nation's primary law for regulating solid waste.

These regulations addressed coal ash disposal, including regulations designed to prevent leaking of contaminants into ground water, blowing of contaminants into the air as dust, and the catastrophic failure of coal ash surface impoundments. Additionally, the CCR rule set out recordkeeping and reporting requirements as well as the requirement for each facility to establish and post specific information to a publicly-accessible website. This final CCR rule also supported the responsible recycling of CCRs by distinguishing safe, beneficial use from disposal.

As explained in the 2015 rule, the ELGs and CCR rules may affect the same unit or activity at a power plant. As such, in finalizing both of those rules in 2015, the EPA coordinated the two rules to minimize the overall complexity and to facilitate implementation of engineering, financial, and permitting activities. The coordination of the two rules continues to be a consideration in the development of today's proposal. The EPA's analysis of this proposal incorporates the same approach used in the 2015 rule to estimate how the CCR rule may affect surface impoundments and the ash handling systems and FGD treatment systems that send wastes to those impoundments. However, as a result of the DC Circuit Court rulings in USWAG v. EPA, No. 15-1219 (DC Cir. 2018) and Waterkeeper Alliance Inc, et al v. EPA, No. 18-1289 (DC Cir. 2019), amendments to the CCR rule are being proposed which would establish a deadline of July 2020 by which all unlined surface impoundments must cease receiving waste subject to certain exceptions.

See the *Supplemental TDD* for details on how the EPA accounted for the CCR rule effects as part of the baseline for this analysis (U.S. EPA, 2019a).

2.3 Market Conditions and Trends in the Electric Power Industry

The 18 percent decline in coal-fueled electricity generation summarized in Table 2-7 for the period of 2012 through 2016 exemplifies an ongoing trend over the last decade: the progressive reduction in generation capacity as coal units and plants retire. In 2018, EIA reported that nearly all of the utility-scale power plants in the United States that were retired from 2008 through 2017 were fueled by fossil fuels, with coal power plants accounting for 47 percent of the total retired capacity (EIA, 2018b). Capacity additions in that same year primarily consisted of natural gas (62 percent), wind (21 percent), and solar photovoltaic (16 percent) capacity (EIA, 2019). Multiple factors contribute to this trend.

One factor in the decline in the coal-fueled power generation is the aging fleet of coal-fired power plants. The life expectancy of coal plants is approximately 40 to 50 years, and almost all plants that retired in 2015 were more than 40 years old (Kolstad, 2017). Mills et al. (2017) also found that coal plants that retired between 2010 and 2016 had an average age of 52 years, and plants with stated plans to retire were not any younger on average. Coal plant retirements due to aging are likely to continue in the near future, as the capacity-weighted average age of coal plants in operation as of 2017 is 39 years (EIA, 2017d).

The lower costs of natural gas, as well as technological advances in solar and wind power have also been important market factors. Fell and Kaffine (2018) found negative impacts on coal-fired generation from both lower natural gas prices and increased wind generation, with declining natural gas prices having a stronger effect. Knittel et al. (2015) found that utilities invested more in natural gas capacity when the prices dropped as a result of the boom in shale gas production, although the magnitude of their investments differed depending on the structure of the electricity market in which they operated.

Changes in electricity generation have had impacts in fuel markets. Coal consumption in the electric power industry has declined by about 40 percent between 2005 and 2017, whereas natural gas consumption has increased by about 24 percent in the same time period, resulting in natural gas consumption doubling coal consumption in 2017 (EIA, 2018c). Market conditions have also negatively affected nuclear-powered generation, though this proposed rule has no effect on the nuclear-powered sector, except as it affects relative prices through its impacts on coal-fired generation (Scott, 2018).

The decline in coal is not independent of environmental regulations affecting coal-fired electricity generation, as power companies have cited regulations promulgated, particularly in the last decade, as reasons for their decision when announcing unit or plant closures, fuel switching, or other operational changes. However, fuel prices and trends toward alternative fuels also appear to be drivers in the shift away from coal for electricity generation. Coglianese et al. (2018) found that the decrease in natural gas prices accounted for 92 percent of the decline in coal production while environmental regulations accounted for 6 percent. Linn and McCormack (2017) found that while air emissions regulations were responsible for most reductions in nitrogen oxides from the electricity sector, they had only a small effect on profitability and retirement at coal plants.

As the electric power infrastructure adjusts to market trends by moving toward optimal infrastructure and operations to deliver the country’s electricity, the EPA recognizes that the changes can have negative effects for some communities and positive effects for others.

3 Compliance Costs

In developing the proposed rule, the EPA assessed the costs and economic impacts of each of the four regulatory options described in Table 1-1. Key inputs for these analyses include the estimated costs to steam electric power plants (and their business, government, or non-profit owners) for implementing control technologies upon which the proposed BAT limitations and pretreatment standards are based,[7] and to the state and federal government for administering this rule. This chapter summarizes the EPA estimates of the incremental compliance costs attributable to the proposal, based on a comparison of steam electric industry compliance costs for the baseline and four regulatory options.[8] The EPA determined that state and federal governments would not incur incremental administrative costs.[9]

The EPA applied the same methodology used to analyze the 2015 rule to calculate industry-level annualized compliance costs. See Chapter 3 of the RIA for the 2015 rule for details (U.S. EPA, 2015b).

The *Supplemental TDD* describes the control technologies and their respective wastewater treatment performance in greater detail (U.S. EPA, 2019a). The *Supplemental TDD* also describes how the EPA estimated plant-specific capital and operation and maintenance (O&M) costs for meeting the BAT limitations and pretreatment standards specified under each of the four regulatory options.

3.1 Analysis Approach and Inputs

The EPA estimated costs to plants for meeting the limitations of the regulatory options. There are four principal steps to compliance cost development, the last two of which are the focus of the discussion below:

1. Determining the set of plants potentially implementing compliance technologies for each regulatory option. See *Supplemental TDD* for details.

2. Developing plant-level costs for each wastestream and regulatory option. See *Supplemental TDD* for details.

3. Estimating the year when each steam electric power plant would be required to meet new BAT effluent limits and pretreatment standards. This schedule supports analysis of the timing of compliance costs and benefits for analyses discussed in this document and in the *BCA*.

4. Estimating *total* industry costs for all plants in the steam electric universe for each of the regulatory options.

An additional step involves comparing the total industry costs from Step 4 to total industry costs similarly obtained for the baseline to estimate the incremental costs attributable to each regulatory option.

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7 Dischargers are not required to use the technologies specified as the basis for the rule. They are free to identify other perhaps less expensive technologies as long as they meet the BAT limitations and pretreatment standards in the rule.

8 The regulatory options would apply only to existing sources, with new sources continuing to be subject to the New Source Performance Standards (NSPS) and Pretreatment Standards for New Sources (PSNS) promulgated in the 2015 rule.

9 As discussed in *Section 10.8: Paperwork Reduction Act of 1995*, the EPA estimates that the regulatory options would not impose additional administrative cost to the State and federal governments.

The EPA reports costs in 2018 dollars and, because the revised ELGs would be effective at a future date, generally discounted costs to 2020, which is the anticipated rule promulgation year.[10]

3.1.1 Plant-Specific Costs Approach

As detailed in the *Supplemental TDD*, the EPA developed costs for steam electric power plants to implement treatment technologies or process changes to control the wastestreams addressed by the regulatory options (*i.e.*, bottom ash transport water and FGD wastewater).

The EPA assessed the operations and treatment system components currently in place at a given unit (or required to be in place to comply with other existing environmental regulations), identified equipment and process changes that plants would likely make to meet the 2015 rule (for baseline) and each of the four regulatory options presented in Table 1-1, and estimated the cost to implement those changes. Because the 2015 rule[11] is the baseline for analysis but is not yet effective for the two wastestreams addressed in the proposal, the EPA first developed costs to meet the 2015 rule based on current plant equipment, processes, and treatment technologies. The EPA then developed similar costs for the regulatory options presented in this proposal. The difference between the baseline and regulatory option cost estimates reflect the incremental costs attributable to the regulatory options. Plants that do not generate a wastewater or that employ technologies which would already meet the given limitations or standards do not incur costs. For several regulatory options, including the proposed option, the costs of meeting the proposed BAT imitations or pretreatment standards are less than those estimated for meeting the 2015 rule, and the options therefore result in cost savings to the industry as compared to the baseline.

3.1.2 Plant-Level Costs

Following the approach used for the analysis of the 2015 rule (U.S. EPA, 2015b), the EPA estimated compliance costs for all existing steam electric power plants, estimated to be a total 951 plants for the point source category overall. The EPA assessed that only a fraction of the universe of steam electric power plants – 479 plants – have the potential to incur any costs under the regulatory options based on their wastestreams. Furthermore, out of these plants, only a subset would incur non-zero costs under any of the scenarios analyzed for the regulatory options, based on existing control technologies: 114 plants under the baseline and 108 plants under the four regulatory options. The *Supplemental TDD* provides additional details on this analysis.

The major components of technology costs are:

- *Capital costs* include the cost of compliance technology equipment, installation, site preparation, construction, and other upfront, non-annually recurring outlays associated with compliance with the regulatory options. The EPA assumes that plants incur all capital costs in the year when their permit is renewed to incorporate the new limitations or standards (see *Technology Implementation Years* below). As explained in the 2015 TDD and Supplemental TDD, all compliance technologies are assumed to have a useful life of 20 years.

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[10] In its analysis of the 2015 rule, the EPA presented costs in 2013 dollars and discounted these compliance costs to 2015 (see U.S. EPA, 2015b).

[11] This includes the September 2017 postponement rule which delayed the earliest compliance date for the ELGs applicable to FGD wastewater and bottom ash transport water.

- *Initial one-time costs* (apart from capital costs, above), if applicable, consist of a one-time cost to make the bottom ash system closed loop to eliminate discharges of bottom ash transport water (*e.g.*, under the baseline) or a one-time cost to develop a Best Management Practice (BMP) plan to recycle bottom ash transport water (*e.g.*, under Option 2). Steam electric power plants are estimated to incur these costs only once during their technology implementation year.

- *Annual fixed O&M costs*, if applicable, include regular *annual* monitoring. Plants incur these costs each year.

- *Annual variable O&M costs*, if applicable, include annual operating labor, maintenance labor and materials, electricity required to operate wastewater treatment systems, chemicals, combustion residual waste transport and disposal operation and maintenance, and savings from not operating and maintaining ash/FGD pond systems. Plants incur these costs each year.

In addition to these initial one-time and annual outlays, certain other costs are estimated to be incurred on a non-annual, periodic basis:

- *3-Yr fixed O&M costs*, if applicable, include mechanical drag system (MDS) chain replacement costs that plants are estimated to incur every three years, beginning three years after the technology implementation year.

- *5-Yr fixed O&M costs*, if applicable, include remote MDS chain replacement costs that plants are estimated to incur every five years, beginning five years after the technology implementation year.

- *6-Yr fixed O&M costs*, if applicable, include mercury analyzer operating and maintenance costs that plants are estimated to incur every six years, beginning in the technology implementation year.

- *10-Yr fixed O&M costs*, if applicable, include savings from not needing to periodically maintain ash/FGD pond systems. Plants are estimated to incur savings every 10 years from not needing to purchase earthmoving equipment for the pond systems, beginning 5 years after the technology implementation year.

Based on information in the record concerning the normal downtime of electricity generating units, the EPA estimated that plants would be able to coordinate the plants' implementation of wastewater treatment systems during already scheduled downtime.

3.1.3 Technology Implementation Years

The years in which individual steam electric power plants are estimated to implement control technologies are an important input to the time profile of costs that plants would incur due to the regulatory options. This profile is used to estimate the change in the annualized costs to the steam electric industry and society associated with the regulatory options in this proposal as compared to the baseline.

The EPA envisions that each plant to which the regulatory options would apply would study available technologies and operational measures, and subsequently install, incorporate, and optimize the technology most appropriate for each site. As part of its consideration of the technological availability and economic achievability of the BAT limitations and pretreatment standards in the rule and following the approach the Agency used for the 2015 rule, the EPA considered the magnitude and complexity of process changes and new equipment installations that would be required at plants to meet the requirements of the regulatory options in determining the time plant owners may need to comply with any revised limitations or pretreatment standards. See discussion in the *Supplemental TDD* (U.S. EPA, 2019a).

As described in greater detail in the proposal, the EPA is proposing a deadline for meeting the BAT limitations and pretreatment standards associated with the four regulatory options that differs across the options, wastestreams, and whether a plant participates in the Voluntary Incentive Program (VIP). Table 3-1 summarizes the relevant deadlines for each regulatory option, based on the wastestream and plant category.

Table 3-1: Compliance Deadlines for the Baseline and Regulatory Options

<table>
<tr><th rowspan="2">Wastestream</th><th rowspan="2">Plant Subset</th><th colspan="5">Compliance “No Later Than” Deadline
(Technology Basis)</th></tr>
<tr><th>Baseline</th><th>Option 1</th><th>Option 2</th><th>Option 3</th><th>Option 4</th></tr>
<tr><td>Bottom Ash Transport Water</td><td>All[a] plants unless otherwise qualified</td><td>2023</td><td>2023</td><td>2023</td><td>2023</td><td>2023</td></tr>
<tr><td rowspan="5">FGD Wastewater</td><td>All[a] plants unless otherwise qualified</td><td>2023
(CP + Biological)</td><td>2023
(CP)</td><td>2025
(CP + LRTR)</td><td>2025
(CP + LRTR)</td><td>2028
(Membranes)</td></tr>
<tr><td>Unit-level net generation ≤876,000 MWh</td><td rowspan="2">Not applicable</td><td rowspan="2">Not applicable</td><td rowspan="2">2023
(CP)</td><td>Not applicable</td><td>Not applicable</td></tr>
<tr><td>Plant-level FGD scrubber purge flow > 4 MGD</td><td>2023
(CP)</td><td>2023
(CP)</td></tr>
<tr><td>VIP</td><td>2023
(CP + Evaporation)</td><td>2028
(Membranes)</td><td>2028
(Membranes)</td><td>2028
(Membranes)</td><td>Not applicable</td></tr>
<tr><td>End of Life Boiler</td><td>2028</td><td>2028</td><td>2028</td><td>2028</td><td>2028</td></tr>
</table>

a. For units with nameplate capacity greater than 50 MW

CP = Chemical precipitation; LRTR = Low Hydraulic Residence Time.

The timing decision represents when the technologies are available, accounting for the need to provide sufficient time for plant owners to raise capital, plan and design systems, procure equipment, and construct and then test systems, recognizing that some plant owners have already met or taken steps to meet the ELGs the EPA finalized in 2015. Moreover, specifying compliance deadlines in the future enables plants to take advantage of planned shutdown or maintenance periods to install new pollution control technologies. This allows for the coordination of generating unit outages in order to maintain grid reliability and prevent any potential impacts on electricity availability caused by forced outages. It is not possible to predict, for each plant, exactly what date any new ELGs would be incorporated into permits, for purposes of determining exactly when plants would incur costs to meet any new requirements. Similar to the approach used in analyzing the 2015 rule, the EPA generally expects plants to meet the new BAT limitations and pretreatment standards in a somewhat staggered fashion, given that (1) for some regulatory options, the permitting authority determines the date after considering certain specified factors, and (2) all permits are not re-issued at the same time due to their 5-year permit term. Thus, for the cost and economic impact analyses, the EPA assumed implementation over a 3- to 5-year period preceding any proposed "no later than" date.[12]

3.1.4 Total Compliance Costs

The EPA used the following methodology and assumptions to aggregate compliance cost components, described in the preceding sections, and develop total plant compliance costs for each regulatory option:

- The EPA estimated compliance costs (including zero costs) for each of the 479 steam electric power plants with the relevant wastestreams, *i.e.*, coal-fired power plants (see *Supplemental TDD* for details). All other plants covered by the steam electric power point source category would incur zero costs.

- The EPA restated compliance costs estimated in the preceding step, accounting for the specific years in which each plant is assumed to undertake compliance-related activities and in 2018 dollars, using the Construction Cost Index (CCI) from McGraw Hill Construction (2017), the Employment Cost Index (ECI) published by the Bureau of Labor Statistics (BLS) (2018), and the Gross Domestic Product (GDP) deflator index published by the U.S. Bureau of Economic Analysis (BEA) (2018).[13]

- The EPA discounted all cost values to 2020, using a rate of 7 percent.[14]

- The EPA annualized one-time costs and costs recurring on other than an annual basis over a specific useful life, implementation, and/or event recurrence period, using a rate of 7 percent:[14]

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12 For the purpose of the analysis, the EPA assigned an estimated compliance year to each of the 479 steam electric power plants analyzed for this proposal based on each plant's estimated NPDES permit renewal year. The EPA projected future NPDES permit years by assuming permits are renewed every 5 years, *i.e.*, a permit expiring in 2020 would be renewed in 2025 and 2030.

13 Specifically, the EPA brought all compliance costs to an estimated technology implementation year using the CCI from McGraw Hill Construction (2017) or the ECI from the Bureau of Labor Statistics (2018), depending on the cost component. The Agency used the average of the year-to-year changes in the CCI (or ECI) over the most recent ten-year reporting period to bring these values to an estimated compliance year. Because the CCI (or ECI) is a nominal cost adjustment index, the resulting technology cost values are as of the compliance year and in the dollars of the technology implementation year. To restate compliance cost values in 2018 dollars, the Agency deflated the nominal dollar values to 2018 using the average of the year-to-year changes in the GDP deflator index published by the BEA over the most recent ten-year reporting period. As a result, all dollar values reported in this analysis are in constant dollars of the year 2018.

14 The rate of 7 percent is used in the cost impact analysis as an estimate of the private opportunity cost of capital. For the social cost analysis presented in Chapter 12 of the BCA document, the EPA uses both 3 percent and 7 percent discount rates. The 3 percent discount rate reflects society's valuation of differences in the timing of consumption; the 7 percent discount rate reflects the opportunity cost of capital to society. In Circular A-4, the Office of Management and Budget (OMB) recommends that 3 percent be used when a regulation affects private consumption, and 7 percent in evaluating a regulation that will mainly displace or alter the use of capital in the private sector (U.S. OMB, 2003; updated 2009). The same discount rates are used for both benefits and costs in the BCA document.

- Capital costs of each compliance technology: 20 years
- Initial one-time costs: 20 years[15]
- 3-Yr O&M: 3 years
- 5-Yr O&M: 5 years
- 6-Yr O&M: 6 years
- 10-Yr O&M: 10 years

- The EPA added annualized capital, initial one-time costs, and annualized O&M costs recurring on other than an annual basis to the annual O&M costs to derive total annualized compliance costs.

For the assessment of compliance costs to steam electric power plants, the EPA considered costs on both a pre-tax and after-tax basis. Pre-tax costs provide insight on the total expenditures as initially incurred by the plants. After-tax costs are a more meaningful measure of compliance impact on privately owned for-profit plants, and incorporate approximate capital depreciation and other relevant tax treatments in the analysis. The EPA calculated the after-tax value of compliance costs by applying combined federal and State tax rates to the pre-tax cost values for privately owned for-profit plants.[16] For this adjustment, the EPA used State corporate rates from the Federation of Tax Administrators (2018) combined with a 21 percent federal corporate tax rate.[17] As discussed in the relevant sections of this document, the EPA uses either pre- or after-tax compliance costs in different analyses, depending on the concept appropriate to each analysis (*e.g.*, cost-to-revenue screening-level analyses are conducted using after-tax compliance costs). Note that for social costs, which are discussed and detailed in Chapter 12 of the BCA document, the EPA uses pre-tax costs.[18]

3.1.5 Voluntary Incentive Program

As described in the proposal, under the VIP component of regulatory options 1, 2, and 3, plants can voluntarily commit to meeting more stringent FGD limitations based on the membrane treatment technology instead of limits based on CP or CP+LRTR technology. VIP participants would have more time – until 2028 – to meet the lower limits based on membranes, as compared to having to meet the limits based on CP in 2023 or CP+LRTR by 2025.

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15 The EPA annualized these non-equipment outlays over 20 years to match the estimated performance life of compliance technology components.

16 Government-owned entities and cooperatives are not subject to income taxes. To distinguish among the government-owned, privately owned, and cooperative ownership categories, the EPA relied on the Steam Electric Survey and additional research on parent entities using publicly available information. See *Chapter 4: Economic Impact Screening Analyses* for further discussion of these determinations.

17 This federal tax rate reflects the Tax Cuts and Jobs Act of 2017 which changed the top corporate tax rate from 35 percent to one flat rate of 21 percent after January 1, 2018.

18 As described in Chapter 12 of the BCA document, the EPA used costs incurred by steam electric power plants for the labor, equipment, material, and other economic resources needed to comply with the regulatory options as a proxy for social costs. The social cost analysis considers costs on an as-incurred, year-by-year basis. In the social cost analysis, the EPA assumed that the market prices for labor, equipment, material, and other compliance resources represent the opportunity costs to society for use of those resources in regulatory compliance. The EPA further assumed that the regulatory options do not affect the aggregate quantity of electricity that would be sold to consumers and, thus, that the rule's social cost would include no changes in consumer and producer surplus *from changes in electricity sales* by the electricity industry in aggregate. Given the small impact of the regulatory options on electricity production cost for the total industry (see *Chapter 5*), this is a reasonable assumption.

Because the VIP is voluntary, the set of plants participating in the program is uncertain. For the purpose of the economic analysis, the EPA estimated VIP participants by comparing the estimated costs of the two technologies for each affected facility and assuming that a plant owner would select the less costly of the two. Specifically, the Agency compared the annualized and discounted cost of implementing CP+LRTR between 2021 and 2025 (based on the plant-specific schedule described in Section 3.1.3) or implementing membranes in 2028. Based on this analysis, the EPA estimated that 18 plants may choose to participate in the VIP under Option 2 and 23 plants may choose to participate in the VIP under Option 3.

3.2 Key Findings for Regulatory Options

3.2.1 Estimated Industry-level Total Compliance Costs

Table 3-2 presents compliance cost estimates for the baseline and each of the four regulatory options. Table 3-3 summarizes *incremental* costs for each option as compared to the baseline. Table 3-4 shows the breakout of incremental total compliance costs for each option by wastestream.

The EPA estimates that, on a *pre-tax* basis, steam electric power plants would incur annualized costs of meeting the regulatory options ranging from $266.8 million under Option 2 to $416.9 million under Option 4 compared to pre-tax costs of $442.4 million for the baseline. Thus, all four options analyzed provide cost savings when compared to the 2015 rule, with pre-tax savings ranging from $25.5 million to $175.6 million (cost savings are shown as negative values in Table 3-3 and Table 3-4). On an *after-tax* basis, the total compliance costs range from $216.3 million to $336.3 million, and cost savings ranging from $26.4 million and $146.5 million, depending on the option. On both the pre-and post-tax bases, compliance costs are lowest, and savings greatest, for Option 2, followed by Option 1, Option 3, and finally Option 4.

All four regulatory options yield annualized costs savings for the bottom ash transport water wastestream. The greatest savings are achieved under Option 2 ($71.7 million after-tax), due to subcategorization of low utilization units under Option 2. Options 1, 2, and 3 provide annualized cost savings for FGD wastewater ranging between $72.1 million and $102.8 million on an after-tax basis, whereas Option 4 results in higher costs for FGD wastewater ($7.3 million on an annualized, after-tax basis), when compared to the baseline.

Table 3-2: Estimated Total Annualized Compliance Costs (in millions, 2018$, at 2020)

Regulatory Option	Pre-Tax Compliance Costs				After-Tax Compliance Costs			
	Capital Technology	Other Initial One-Time[a]	Total O&M	Total	Capital Technology	Other Initial One-Time[a]	Total O&M	Total
Baseline	$280.3	$0.01	$162.1	$442.4	$229.4	$0.0	$133.4	$362.8
Option 1	$162.9	$0.01	$113.8	$276.8	$132.3	$0.0	$93.8	$226.2
Option 2	$156.0	$0.08	$110.7	$266.8	$125.4	$0.1	$90.9	$216.3
Option 3	$176.9	$0.01	$139.2	$316.1	$142.5	$0.0	$114.4	$256.9
Option 4	$210.2	$0.01	$206.6	$416.9	$169.0	$0.0	$167.4	$336.3

Source: U.S. EPA Analysis, 2019

Table 3-3: Estimated Incremental Annualized Compliance Costs (in millions, 2018$, at 2020)

Regulatory Option	Pre-Tax Incremental Costs				After-Tax Incremental Costs			
	Net Capital Technology	Net Other Initial One-Time[a]	Net Total O&M	Net Total Costs	Net Capital Technology	Net Other Initial One-Time[a]	Net Total O&M	Net Total Costs
Option 1	-$117.4	$0.00	-$48.2	-$165.6	-$97.0	$0.0	-$39.6	-$136.6
Option 2	-$124.3	$0.07	-$51.4	-$175.6	-$104.0	$0.1	-$42.5	-$146.5
Option 3	-$103.5	$0.00	-$22.9	-$126.3	-$86.8	$0.0	-$19.0	-$105.9
Option 4	-$70.1	$0.00	$44.5	-$25.5	-$60.4	$0.0	$34.0	-$26.4

Source: U.S. EPA Analysis, 2019

Table 3-4: Estimated Incremental Annualized Compliance Costs, by Wastestream (in millions, 2018$, at 2020)

Regulatory Option	Pre-Tax Incremental Costs			After-Tax Incremental Costs		
	Bottom Ash Transport Water	FGD Wastewater	Net Total Costs	Bottom Ash Transport Water	FGD Wastewater	Net Total Costs
Option 1	-$42.8	-$122.9	-$165.6	-$33.8	-$102.8	-$136.6
Option 2	-$89.1	-$86.5	-$175.6	-$71.7	-$74.7	-$146.5
Option 3	-$42.8	-$83.6	-$126.3	-$33.8	-$72.1	-$105.9
Option 4	-$42.8	$17.2	-$25.5	-$33.8	$7.3	-$26.4

Source: U.S. EPA Analysis, 2019

3.2.2 Estimated Regional Distribution of Total Compliance Costs

Table 3-5 reports incremental costs for each regulatory option at the level of a North American Electric Reliability Corporation (NERC) region (see Table 2-5).[19] As explained in *Chapter 2* (Overview of the Steam Electric Industry), because of differences in operating characteristics of steam electric power plants across NERC regions, as well as differences in the economic and electric power system regulatory circumstances of the NERC regions themselves, the regulatory options may affect costs, profitability, electricity prices, and other impact measures differently across NERC regions.

Annualized after-tax compliance costs are highest in the SERC and RFC regions for all regulatory options, and, as shown in Table 3-5, these regions also see the greatest incremental cost savings across options 1, 2, and 3. SERC also has the largest cost savings under Option 4.

[19] No steam electric power plant is estimated to incur compliance costs in the ASCC and HICC NERC regions and these two regions are therefore omitted from the presentation of results.

Table 3-5: Estimated Annualized Incremental Compliance Costs by NERC Region (in millions, 2018$, at 2020)

NERC Region[a]	Pre-Tax Incremental Compliance Costs				After-Tax Incremental Compliance Costs			
	Capital Technology	Other Initial One-Time	Total O&M	Total	Capital Technology	Other Initial One-Time	Total O&M	Total
Option 1								
FRCC	-$6.4	$0.0	-$2.2	-$8.5	-$5.1	$0.0	-$1.8	-$7.0
MRO	-$3.1	$0.0	-$1.3	-$4.4	-$2.8	$0.0	-$1.2	-$4.0
NPCC	-$1.2	$0.0	-$0.6	-$1.8	-$0.9	$0.0	-$0.5	-$1.3
RFC	-$40.9	$0.0	-$18.8	-$59.8	-$31.3	$0.0	-$14.3	-$45.6
SERC	-$59.7	$0.0	-$22.5	-$82.2	-$52.1	$0.0	-$19.5	-$71.6
SPP	-$4.2	$0.0	-$1.8	-$6.1	-$3.3	$0.0	-$1.4	-$4.7
TRE	-$1.6	$0.0	-$0.9	-$2.4	-$1.4	$0.0	-$0.8	-$2.1
WECC	-$0.3	$0.0	-$0.1	-$0.4	-$0.3	$0.0	-$0.1	-$0.3
Total	**-$117.4**	**$0.0**	**-$48.2**	**-$165.6**	**-$97.0**	**$0.0**	**-$39.6**	**-$136.6**
Option 2								
FRCC	-$3.7	$0.0	-$0.2	-$3.9	-$3.0	$0.0	-$0.2	-$3.2
MRO	-$7.1	$0.0	-$5.0	-$12.1	-$6.6	$0.0	-$4.7	-$11.3
NPCC	-$3.7	$0.0	-$3.1	-$6.8	-$2.7	$0.0	-$2.3	-$5.0
RFC	-$39.4	$0.0	-$14.7	-$54.1	-$30.1	$0.0	-$11.2	-$41.3
SERC	-$61.6	$0.0	-$25.2	-$86.8	-$54.2	$0.0	-$21.4	-$75.6
SPP	-$4.4	$0.0	-$1.9	-$6.3	-$3.4	$0.0	-$1.5	-$4.9
TRE	-$2.6	$0.0	-$0.6	-$3.2	-$2.3	$0.0	-$0.5	-$2.8
WECC	-$1.8	$0.0	-$0.7	-$2.5	-$1.7	$0.0	-$0.7	-$2.4
Total	**-$124.3**	**$0.1**	**-$51.4**	**-$175.6**	**-$104.0**	**$0.1**	**-$42.5**	**-$146.5**
Option 3								
FRCC	-$3.7	$0.0	-$0.2	-$3.9	-$3.0	$0.0	-$0.2	-$3.2
MRO	-$4.0	$0.0	-$1.0	-$5.1	-$3.7	$0.0	-$0.9	-$4.7
NPCC	-$0.9	$0.0	-$0.3	-$1.3	-$0.7	$0.0	-$0.2	-$0.9
RFC	-$32.9	$0.0	-$8.3	-$41.3	-$25.2	$0.0	-$6.2	-$31.4
SERC	-$55.0	$0.0	-$11.1	-$66.1	-$48.6	$0.0	-$9.9	-$58.5
SPP	-$3.9	$0.0	-$1.2	-$5.2	-$3.0	$0.0	-$1.0	-$4.0
TRE	-$2.6	$0.0	-$0.6	-$3.2	-$2.3	$0.0	-$0.5	-$2.8
WECC	-$0.3	$0.0	-$0.1	-$0.4	-$0.3	$0.0	-$0.1	-$0.3
Total	**-$103.5**	**$0.0**	**-$22.9**	**-$126.3**	**-$86.8**	**$0.0**	**-$19.0**	**-$105.9**
Option 4								
FRCC	-$0.1	$0.0	$5.5	$5.4	-$0.3	$0.0	$4.2	$3.9
MRO	-$4.0	$0.0	-$0.9	-$4.9	-$3.7	$0.0	-$0.8	-$4.5
NPCC	-$1.0	$0.0	$0.0	-$1.0	-$0.8	$0.0	$0.0	-$0.7
RFC	-$24.3	$0.0	$20.5	-$3.8	-$18.5	$0.0	$15.8	-$2.7
SERC	-$35.1	$0.0	$19.6	-$15.5	-$32.6	$0.0	$15.0	-$17.6
SPP	-$2.8	$0.0	$0.4	-$2.4	-$2.2	$0.0	$0.3	-$1.9
TRE	-$2.5	$0.0	-$0.5	-$2.9	-$2.2	$0.0	-$0.4	-$2.6
WECC	-$0.3	$0.0	-$0.1	-$0.4	-$0.3	$0.0	-$0.1	-$0.3
Total	**-$70.1**	**$0.0**	**$44.5**	**-$25.5**	**-$60.4**	**$0.0**	**$34.0**	**-$26.4**

a. The EPA estimated zero ELG compliance costs in the ASCC and HICC regions. These two regions are omitted from the table presentation. This omission does not affect totals.

Source: U.S. EPA Analysis, 2019

3.3 Key Uncertainties and Limitations

Economic analyses are not perfect predictions and thus, like all such analyses, this analysis has some uncertainties and limitations.

- The compliance costs used in this analysis reflect unit retirements, conversions, and repowerings announced through October 2018 and scheduled to occur by the end of 2028. For details, see memorandum entitled "*Changes to Industry Profile for Coal-Fired Generating Units for the Steam Electric Effluent Guidelines Proposed Rule*" (DCN SE07207 in the rule docket). To the extent that actual unit retirements, conversions, and repowerings at steam electric power plants differ from announced changes, estimated annualized compliance costs may differ from actual costs.

- The EPA assumed that the equipment installed to meet any new limitations could reasonably be estimated to operate for 20 years or more, based on a review of reported performance characteristics of the equipment components. The EPA thus used 20 years as the basis for the cost and economic impact analyses that account for the estimated operating life of compliance technology. To the extent that the actual service life is longer or shorter than 20 years, costs presented on annual equivalent basis would be over- or under-stated.

- Annualized compliance costs depend on the assumed technology implementation year. For the purpose of the cost and economic impact analyses, the EPA determined years in which technology implementation would reasonably be estimated to occur across the universe of steam electric power plants, based on plant-specific information about existing NPDES permits and extrapolating future permit issuance dates assuming permits are renewed every five years. To the extent that compliance costs are incurred in an earlier or later year, the annualized values presented in this section may under or overstate the annualized total costs of the regulatory options.

- The EPA estimated VIP participants for options 2 and 3 based on the lowest cost technology on an annualized and discounted basis, but plant owners may consider other factors in deciding whether to participate in the VIP so actual participation may be higher or lower than projected.

4 Cost and Economic Impact Screening Analyses

4.1 Analysis Overview

Following the same methodology used for the 2015 rule analysis (U.S. EPA, 2015b), the EPA assessed the costs and economic impacts of the regulatory options in two ways:

1. A screening-level assessment reflecting current operating characteristics of steam electric power plants and with assignment of estimated compliance costs to those plants. This analysis assumes no changes in operating characteristics – *e.g.*, quantity of generated electricity and revenue – as a result of the regulatory options. This screening-level assessment, which is documented in this chapter, includes two specific analyses:

   − A cost-to-revenue screening analysis to assess the impact of compliance outlays on individual steam electric power plants (Section 4.2)
   − A cost-to-revenue screening analysis to assess the impact of compliance outlays on domestic parent-entities owning steam electric power plants (Section 4.3)

2. A broader electricity market-level analysis based on IPM (the Market Model Analysis). This analysis, which provides a more comprehensive indication of the economic achievability of the regulatory options that the EPA evaluated, including an assessment of incremental plant closures (or avoided closures), is discussed in Chapter 5. Unlike the preceding analysis discussed in this chapter, the Market Model Analysis accounts for estimated changes in the operating characteristics of plants from both estimated changes in electricity markets and operating characteristics of plants independent of and as a result of the regulatory options.

4.2 Cost-to-Revenue Analysis: Plant-Level Screening Analysis

The cost-to-revenue measure compares the cost of implementing and operating compliance technologies with the plant's operating revenue and provides a screening-level assessment of the impact that might be estimated of the regulatory options. As discussed in U.S. EPA (2015b; see Chapter 2), the majority of steam electric power plants operate in states with regulated electricity markets. The EPA estimates that plants located in these states may be able to recover any compliance cost-based increases in their production costs through increased electricity prices, depending on the business operation model of the plant owner(s), the ownership and operating structure of the plant itself, and the role of market mechanisms used to sell electricity. In contrast, in states in which electric power generation has been deregulated, cost recovery is not guaranteed. While plants operating within deregulated electricity markets *may be* able to recover some of their additional production costs through increased revenue, it is not possible to determine the extent of cost recovery ability for each plant.[20] Note that the EPA estimates that the converse also applies – plants operating in regulated markets are more likely to pass on any decline in production costs to their customer as reduced rates, whereas customer savings are not guaranteed in deregulated markets.

[20] While the regulatory status in a given state affects the ability of electric power plants and their parent entities to recover electricity generation costs, it is not the only factor and should not be used solely as the basis for cost-pass-through determination.

In assessing the cost impact of the baseline and four regulatory options on steam electric power plants in this screening-level analysis, the Agency assumed that the plants would not be able to pass any of the change in their production costs to consumers (zero cost pass-through). This assumption is used for analytic convenience and provides a *worst-case* scenario of regulatory impacts to steam electric power plants.[21]

4.2.1 Analysis Approach and Data Inputs

As described in *Chapter 1* as proposed, the EPA estimates all steam electric power plants to meet any new requirements for bottom ash transport water and FGD wastewater beginning in 2021, with compliance occurring as late as 2028 for certain plants, wastestreams, and regulatory options.

Using the same approach as used for the 2015 rule (U.S. EPA, 2015b), the EPA analyzed the impacts of the baseline first, and then conducted the same analysis for each of the four regulatory options. The difference in findings between the regulatory options and baseline provides insight into the potential impacts of the regulatory options.

The EPA updated the approach used for the 2015 rule to incorporate more recent data. For the current analysis, the EPA used 2020 as the basis for comparing after-tax compliance costs (see *Chapter 3*) to revenue at the plant level.[22,] For this comparison, the EPA developed plant-level revenue values for all steam electric power plants using data from the Department of Energy's Energy Information Administration (EIA) on electricity generation by prime mover, and utility/operator-level electricity prices and disposition. Specifically, the EPA multiplied the 6-year average of electricity generation values over the period 2011 to 2016 from the EIA-923 database by 6-year average electricity prices over the period 2011 to 2016 from the EIA-861 database (EIA, 2017b; EIA, 2017c).[23, 24] The EPA estimated compliance costs in 2018 dollars. To provide cost and revenue comparisons on a consistent analysis-year (2020) and dollar-year (2018) basis, the EPA adjusted the EIA electricity price data, which are reported in nominal dollars of each year.

Cost-to-revenue ratios are used to describe impacts to entities because they provide screening-level indicators of potential economic impacts. Just as for the plants owned by small entities under guidance in

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21 Even though the majority of steam electric power plants may be able to pass increases in production costs to consumers through increased electricity prices, it is difficult to determine exactly which plants would be able to do so. Consequently, the EPA concluded that assuming zero cost pass-through is appropriate as a screening-level, upper bound estimate of the potential impact of compliance expenditures on steam electric power plants and their parent entities. The analysis, while helpful to understand potential cost impact, does not generally indicate whether profitability is jeopardized, cash flow is affected, or risk of financial distress is increased.

22 For private, tax-paying entities, *after-tax costs* are a more relevant measure of potential private cost burden than *pre-tax costs*. For non-tax-paying entities (*e.g.*, State government and municipality owners of steam electric power plants), the estimated costs used in this calculation include no adjustment for taxes.

23 In using the year-by-year revenue values to develop an average over the data years, the EPA set aside from the average calculation any generation values that are anomalously low. Such low generating output likely results from temporary disruption in operation, such as a generating unit being out of service for maintenance.

24 EPA's first step in calculating plant revenue was to restate electricity prices in 2018 dollars using the Gross Domestic Product (GDP) deflator index published by the U.S. Bureau of Economic Analysis (BEA) (2018). These individual yearly values were then averaged and brought forward to 2020 using electricity price projections from the Annual Energy Outlook publication for 2018 (AEO2018) (EIA, 2018a). AEO2018 contains projections and analysis of U.S. energy supply, demand, and prices through 2050. AEO2018 electricity price projections are in constant dollars; therefore, these adjustments yield 2020 revenue values in dollars of the year 2018.

U.S. EPA (2006), and the approach EPA has used previously in analyses of the 2015 ELG rule (U.S. EPA, 2015b) and 316(b) Existing Facilities Rule (U.S. EPA, 2014), the EPA assesses plants incurring costs below one percent of revenue as unlikely to face material economic impacts, plants with costs of at least one percent but less than three percent of revenue as having a higher chance of facing material economic impacts, and plants incurring costs of at least three percent of revenue as having a still higher probability of material economic impacts.

4.2.2 Key Findings for Regulatory Options

The EPA estimates that for 930 steam electric power plants, including those estimated to incur zero compliance costs, costs would not exceed the one percent of revenue threshold under the baseline. Table 4-1 presents cost-to-revenue analysis results for the baseline, while Table 4-2 presents results for the four regulatory options relative to the baseline. Under all four regulatory options, most plants would not experience significant changes in their cost-to-revenue ratios compared to baseline costs. However, additional plants would fall under the one percent of revenue threshold, as shown in Table 4-2, which reports changes in plant-level cost-to-revenue results by owner type and regulatory option. Under Option 4, one investor-owned plant moves up one cost-to-revenue threshold, from less than one percent under the baseline scenario to between one and three percent, while 7 other plants move to lower cost-to-revenue thresholds. Of these 7 plants, 6 plants incur no additional costs compared to baseline,[25] and one municipality-owned plant moves from the greater than three percent threshold under baseline to between one and three percent. As for Options 1, 2, and 3, all plants that experience changes in cost-to-revenue thresholds shift downwards. For details on cost-to-revenue results for small entities, see Section 8.2.

Table 4-1: Plant-Level Cost-to-Revenue Analysis Results for the Baseline by Owner Type

Owner Type	Total Number of Plants[a]	Number of Plants with a Ratio of			
		0%[a,b]	≠0 and <1%	≥1 and 3%	≥3%
Baseline					
Cooperative	64	54	7	3	0
Federal	20	14	4	2	0
Investor-owned	509	429	75	4	1
Municipality	123	108	6	2	5
Nonutility	198	195	2	0	0
Political Subdivision	34	33	0	1	0
State	4	2	2	0	0
Total	**951**	**834**	**96**	**12**	**6**

a. Plant counts are weighted estimates

b. These plants already meet discharge requirements for the wastestreams controlled by a given regulatory option and therefore are not estimated to incur compliance costs.

Source: U.S. EPA Analysis, 2019.

25 The six plants would incur costs to meet bottom ash transport water requirements under the baseline, based on dry handling / closed loop system, but would not incur costs under the regulatory options, based on High Recycle Rate Systems.

Table 4-2: Plant-Level Incremental Cost-to-Revenue Analysis Results by Owner Type and Regulatory Option

Owner Type	Δ Total Number of Plants[a]	Δ Number of Plants with a Ratio of			
		0%[a,b]	≠0 and <1%	≥1 and 3%	≥3%
Option 1					
Cooperative	0	0	0	0	0
Federal	0	2	-2	0	0
Investor-owned	0	4	-3	0	-1
Municipality	0	0	1	0	-1
Nonutility	0	0	0	0	0
Political Subdivision	0	0	0	0	0
State	0	0	0	0	0
Total	**0**	**6**	**-4**	**0**	**-2**
Option 2					
Cooperative	0	0	1	-1	0
Federal	0	2	-2	0	0
Investor-owned	0	4	-1	-3	0
Municipality	0	0	5	-1	-4
Nonutility	0	0	0	0	0
Political Subdivision	0	0	1	-1	0
State	0	0	0	0	0
Total	**0**	**6**	**4**	**-6**	**-4**
Option 3					
Cooperative	0	0	0	0	0
Federal	0	2	-2	0	0
Investor-owned	0	4	-4	0	0
Municipality	0	0	1	0	-1
Nonutility	0	0	0	0	0
Political Subdivision	0	0	0	0	0
State	0	0	0	0	0
Total	**0**	**6**	**-5**	**0**	**-1**
Option 4					
Cooperative	0	0	0	0	0
Federal	0	2	-2	0	0
Investor-owned	0	4	-5	1	0
Municipality	0	0	0	1	-1
Nonutility	0	0	0	0	0
Political Subdivision	0	0	0	0	0
State	0	0	0	0	0
Total	**0**	**6**	**-7**	**2**	**-1**

a. Plant counts are weighted estimates

b. These plants already meet discharge requirements for the wastestreams controlled by a given regulatory option and therefore are not estimated to incur compliance costs.

Source: U.S. EPA Analysis, 2019.

4.2.3 Uncertainties and Limitations

Despite the EPA's use of the best available information and data, this analysis of plant-level impacts has uncertainties and limitations, including:

- The impact of the regulatory options may be over- or under-estimated as a result of differences between actual 2020 plant revenue and those estimated using EIA databases for 2011 through 2016.
- As noted above, the zero cost pass-through assumption represents a worst-case scenario from the perspective of the plant owner. To the extent that companies are able to pass some compliance costs on to consumers through higher electricity prices, this analysis overstates the potential impact of the baseline and regulatory options on steam electric power plants.

4.3 Cost-to-Revenue Screening Analysis: Parent Entity-Level Analysis

Following the methodology the EPA used for the analysis of the 2015 rule (U.S. EPA, 2015b), the EPA also assessed the economic impact of the regulatory options at the parent entity level. The cost-to-revenue screening analysis at the entity level adds particular insight on the impact of compliance requirements on those entities that own multiple plants.

The EPA conducted this screening analysis at the *highest* level of *domestic* ownership, referred to as the "domestic parent entity." For this analysis, the Agency considered only entities with the largest share of ownership (*e.g.*, majority owner) in at least one surveyed steam electric power plant.[26,27] The entity-level analysis maintains the worst-case analytical assumption of no pass-through of compliance costs to electricity consumers used for the plant-level cost-to-revenue analysis in Section 4.2.

4.3.1 Analysis Approach and Data Inputs

Following the approach used in the 2015 rule (U.S. EPA, 2015b), to assess the entity-level economic/financial impact of compliance requirements, the EPA summed plant-level annualized after-tax compliance costs calculated in Section 3.2 to the level of the steam electric power plant owning entity and compared these costs to parent entity revenue.

Similar to the plant-level analysis, the EPA used cost-to-revenue ratios of one and three percent as markers of potential impact for this analysis. Also similar to the assumptions made for the plant-level analysis, for this entity-level analysis the Agency assumed that entities incurring costs below one percent of revenue are unlikely to face significant economic impacts, while entities with costs of at least one percent but less than three percent of revenue have a higher chance of facing significant economic impacts, and entities incurring costs of at least three percent of revenue have a still higher probability of significant economic impacts.

26 Throughout these analyses, the EPA refers to the owner with the largest ownership share as the "majority owner" even when the ownership share is less than 51 percent.

27 When two entities have equal ownership shares in a plant (*e.g.*, 50 percent each), the EPA analyzed both entities and allocated plant-level compliance costs to each entity.

Following the approach used in in the 2015 rule (2015b; see Section 4.3), the EPA analyzed two cases that provide approximate upper and lower bound estimates on: (1) the number of entities incurring compliance costs and (2) the costs incurred by any entity owning one or more steam electric power plant.

This entity-level cost-to-revenue analysis involved the following steps: (1) Determining the parent entity; (2) Determining the parent entity revenue; and (3) Estimating compliance costs at the level of the parent entity. The sections below highlight updates to incorporate more recent data than were used in U.S. EPA (2015b).

Determining the Parent Entity

The EPA used information from the 2016 EIA-860 database which provides owners and the share of ownership in electric generating units (EIA, 2017a) to determine ownership of each coal-fired steam electric power plant and surveyed non-coal steam electric power plants (see U.S. EPA, 2015b for discussion of how non-coal steam electric power plants are incorporated in the analysis). The EPA supplemented this information with data from corporate/financial websites and from the Steam Electric Survey to identify the highest level domestic parent entity for each plant.

Determining Parent Entity Revenue

For each parent entity identified in the preceding step, the EPA determined revenue values based on information from corporate or financial websites, if those values were available. The EPA tried to obtain revenue for as many years within 2015 through 2017 and used the average of reported values. If revenue values were not reported on corporate/financial websites, the Agency used 2013-2016 average revenue values from the EIA-861 database (EIA, 2017b).

The EPA restated entity revenue values in 2018 dollars using the GDP Deflator. For this analysis, the Agency assumed that these average historical revenue values are representative of revenues as of 2020. Although the entity-level revenue values might reasonably be estimated to change by 2020 (*i.e.*, have increased or decreased relative to average historical revenue), the EPA was less confident in the reliability of projecting revenue values *at the entity level* than in that of projecting plant-level revenue values to reflect changes in generation. For the entity-level analysis, therefore, the EPA did not project or further adjust revenue values developed using the sources and methodology described above but used these values *as is*. In effect, plants and their parent entities are assumed to be the same 'business entities' in terms of constant dollar revenue in 2020 as they were in the year for which revenue were reported.

Estimating Compliance Costs at the Level of the Parent Entity

Following the approach used in the analysis of the 2015 rule, to account for the parent entities of all 951 steam electric power plants, the EPA analyzed two approximate bounding cases that provide a range of estimates for the number of entities incurring compliance costs and the costs incurred by any entity owning a steam electric power plant: (1) A lower bound estimate that assumes that the surveyed owners represent all owners, which effectively assumes that any non-surveyed plants are owned by the same surveyed entities and maximizes the number of plants owned by any given entity; and (2) An upper bound estimate that assumes that the non-surveyed owners are different from those surveyed but have similar characteristics, which results in a greater number of owners but minimizes the number of plants owned by each. See Chapter 4 in U.S. EPA (2015b) for details.

4.3.2 Key Findings for Regulatory Options

Table 4-3 and Table 4-4 summarize the results from the entity-level impact analysis under the lower bound (Case 1) and upper bound (Case 2) estimates of the number of entities incurring costs. Table 4-3 presents results under the baseline, while Table 4-4 presents results under the four regulatory options relative to the baseline. The tables show the number of entities that incur costs in four ranges: no cost, non-zero costs less than one percent of an entity's revenue, at least one percent but less than three percent of revenue, and at least three percent of revenue.

The EPA estimates that between 243 and 478 parent entities own steam electric power plants based on the range indicated by Case 1 and Case 2, respectively. Under the baseline in Case 1, 236 parent entities are estimated to incur costs less than one percent of revenue, and in Case 2, this number is 470 parent entities. When examining changes in number of parent entities that shift across cost-to-revenue thresholds, as shown in Table 4-4, most entities stay within the same threshold. [28] However, where there are changes across thresholds, these changes all move downward, i.e., smaller impacts relative to revenue. Under the most stringent regulatory option the EPA analyzed, Option 4, one municipality-owned entity moves down one impact threshold, from between one and three percent to less than one percent, and one investor-owned entity also moves down one threshold, from between one and three percent to incurring no costs.

Overall, this screening-level analysis shows that few entities are likely to experience significant changes in compliance costs compared to revenues, and economic impacts to these entities would be lessened across all options.

Table 4-3: Baseline Entity-Level Cost-to-Revenue Analysis Results

	Case 1: Lower bound estimate of number of firms owning plants that face requirements under the regulatory analysis						Case 2: Upper bound estimate of number of firms owning plants that face requirements under the regulatory analysis					
	Total Number of Entities	Number of Entities with a Ratio of					Total Number of Entities	Number of Entities with a Ratio of				
Entity Type		0%[a]	≠0 and <1%	≥1 and 3%	≥3%	Unknown		0%[a]	≠0 and <1%	≥1 and 3%	≥3%	Unknown[b]
Baseline												
Cooperative	28	18	10	0	0	0	50	40	10	0	0	0
Federal	1	0	1	0	0	0	3	2	1	0	0	0
Investor-owned	69	38	30	1	0	0	157	126	30	1	0	0
Municipality	59	46	7	4	2	0	94	81	7	4	2	0
Nonutility	74	72	2	0	0	0	150	147	2	0	0	1
Other Political Subdivision	10	9	1	0	0	0	21	20	1	0	0	0

28 The results include entities that own only steam electric power plants that already meet discharge requirements for the wastestreams addressed by a given regulatory option and are therefore not estimated to incur any compliance technology costs.

Table 4-3: Baseline Entity-Level Cost-to-Revenue Analysis Results

Entity Type	Case 1: Lower bound estimate of number of firms owning plants that face requirements under the regulatory analysis						Case 2: Upper bound estimate of number of firms owning plants that face requirements under the regulatory analysis					
	Total Number of Entities	Number of Entities with a Ratio of					Total Number of Entities	Number of Entities with a Ratio of				
		0%[a]	≠0 and <1%	≥1 and 3%	≥3%	Unknown		0%[a]	≠0 and <1%	≥1 and 3%	≥3%	Unknown[b]
State	2	1	1	0	0	0	2	1	1	0	0	0
Total	**243**	**184**	**52**	**5**	**2**	**0**	**478**	**418**	**52**	**5**	**2**	**1**

a. These entities own only plants that already meet discharge requirements for the wastestreams addressed by a given regulatory option and are therefore not estimated to incur any compliance technology costs.

b. The EPA was unable to determine revenues for one parent entity under Case 2.

Source: U.S. EPA Analysis, 2019.

Table 4-4: Entity-Level Incremental Cost-to-Revenue Analysis Results

Entity Type	Case 1: Lower bound estimate of change in number of firms owning plants that face requirements under the regulatory analysis						Case 2: Upper bound estimate of change in number of firms owning plants that face requirements under the regulatory analysis					
	Δ Total Number of Entities	Δ Number of Entities with a Ratio of					Δ Total Number of Entities	Δ Number of Entities with a Ratio of				
		0%[a]	≠0 and <1%	≥1 and 3%	≥3%	Unknown		0%[a]	≠0 and <1%	≥1 and 3%	≥3%	Unknown
Option 1												
Cooperative	0	0	0	0	0	0	0	0	0	0	0	0
Federal	0	0	0	0	0	0	0	0	0	0	0	0
Investor-owned	0	1	-1	0	0	0	0	1	-1	0	0	0
Municipality	0	0	2	-2	0	0	0	0	2	-2	0	0
Nonutility	0	0	0	0	0	0	0	0	0	0	0	0
Other[b]	0	0	0	0	0	0	0	0	0	0	0	0
State	0	0	0	0	0	0	0	0	0	0	0	0
Total	**0**	**1**	**1**	**-2**	**0**	**0**	**0**	**1**	**1**	**-2**	**0**	**0**
Option 2												
Cooperative	0	0	0	0	0	0	0	0	0	0	0	0
Federal	0	0	0	0	0	0	0	0	0	0	0	0
Investor-owned	0	1	0	-1	0	0	0	1	0	-1	0	0
Municipality	0	0	4	-3	-1	0	0	0	4	-3	-1	0
Nonutility	0	0	0	0	0	0	0	0	0	0	0	0
Other[b]	0	0	0	0	0	0	0	0	0	0	0	0
State	0	0	0	0	0	0	0	0	0	0	0	0
Total	**0**	**1**	**4**	**-4**	**-1**	**0**	**0**	**1**	**4**	**-4**	**-1**	**0**

Table 4-4: Entity-Level Incremental Cost-to-Revenue Analysis Results

Entity Type	Case 1: Lower bound estimate of change in number of firms owning plants that face requirements under the regulatory analysis						Case 2: Upper bound estimate of change in number of firms owning plants that face requirements under the regulatory analysis					
	Δ Total Number of Entities	Δ Number of Entities with a Ratio of					Δ Total Number of Entities	Δ Number of Entities with a Ratio of				
		0%[a]	≠0 and <1%	≥1 and 3%	≥3%	Unknown		0%[a]	≠0 and <1%	≥1 and 3%	≥3%	Unknown
Option 3												
Cooperative	0	0	0	0	0	0	0	0	0	0	0	0
Federal	0	0	0	0	0	0	0	0	0	0	0	0
Investor-owned	0	1	-1	0	0	0	0	1	-1	0	0	0
Municipality	0	0	2	-2	0	0	0	0	2	-2	0	0
Nonutility	0	0	0	0	0	0	0	0	0	0	0	0
Other[b]	0	0	0	0	0	0	0	0	0	0	0	0
State	0	0	0	0	0	0	0	0	0	0	0	0
Total	**0**	**1**	**1**	**-2**	**0**	**0**	**0**	**1**	**1**	**-2**	**0**	**0**
Option 4												
Cooperative	0	0	0	0	0	0	0	0	0	0	0	0
Federal	0	0	0	0	0	0	0	0	0	0	0	0
Investor-owned	0	1	-1	0	0	0	0	1	-1	0	0	0
Municipality	0	0	1	-1	0	0	0	0	1	-1	0	0
Nonutility	0	0	0	0	0	0	0	0	0	0	0	0
Other[b]	0	0	0	0	0	0	0	0	0	0	0	0
State	0	0	0	0	0	0	0	0	0	0	0	0
Total	**0**	**1**	**0**	**-1**	**0**	**0**	**0**	**1**	**0**	**-1**	**0**	**0**

a. These entities own only plants that already meet discharge requirements for the wastestreams addressed by a given regulatory option and are therefore not estimated to incur any compliance technology costs.

b. Other political subdivision.

Source: U.S. EPA Analysis, 2019.

4.3.3 Uncertainties and Limitations

Despite the EPA's use of the best available information and data, this analysis of entity-level impacts has uncertainties and limitations, including:

- The entity-level revenue values obtained from the corporate and financial websites or EIA databases are for 2015 through 2017. To the extent that actual 2020 entity revenue values are different, on a constant dollar basis, from those estimated using historical data, the cost-to-revenue measure for parent entities of steam electric power plants may be over- or under-estimated.

- The assessment of entity-level impacts relies on approximate upper and lower bound estimates of the number of parent entities and the numbers of steam electric power plants that these entities own. The EPA expects that the range of results from these analyses provides appropriate insight into the overall extent of entity-level effects.

- As is the case with the plant-level analysis discussed in Section 4.2, the zero cost pass-through assumption represents a worst-case scenario from the perspective of the plant owner. To the extent that companies are able to pass some compliance costs on to consumers through higher electricity prices, this analysis overstates the potential impact of the baseline and regulatory options on steam electric power plants.

5 Assessment of the Impact of the Regulatory Options in the Context of National Electricity Markets

Following the approach used to analyze the impacts of the 2015 rule and other various regulatory actions affecting the electric power sector over the last decade, the EPA used the Integrated Planning Model (IPM®), a comprehensive electricity market optimization model that can evaluate such impacts within the context of regional and national electricity markets. To assess plant- and market-level effects of the regulatory options considered for the proposed rule, the EPA used the latest version of this analytic system: Integrated Planning Model Version 6 (IPM V6) (U.S. EPA, 2018a).[29]

The market model analysis is a more comprehensive analysis compared to the screening-level analyses discussed in *Chapter 4: Cost and Economic Impact Screening Analyses*; it is meant to inform the EPA's assessment of whether the regulatory options would result in any capacity retirements (full or partial plant closures)[30] and to provide insight on the impact of the regulatory options on the overall electricity market, including to assess whether the regulatory options may significantly affect the energy supply, distribution or use under Executive Order 13211 (see Section 10.7). In allocating resources to analytical effort, the EPA chose to run IPM for Options 2 and 4 because these two options bound the costs of the proposal and IPM results therefore capture the range of impacts that may result from the four regulatory options.

In contrast to the screening-level analyses, which are static analyses and do not account for interdependence of electric generating units in supplying power to the electric transmission grid, IPM accounts for potential changes in the generation profile of steam electric and other units and consequent changes in market-level generation costs, as the electric power market responds to changes in generation costs for steam electric units due to the regulatory options. IPM is also dynamic in that it is capable of using forecasts of future conditions to make decisions for the present. Additionally, in contrast to the screening-level analyses in which EPA assumed no pass through of compliance costs, IPM depicts production activity in wholesale electricity markets where some recovery of compliance costs through increased electricity prices is possible but not guaranteed. Finally, IPM incorporates electricity demand growth assumptions from the Department of Energy's *Annual Energy Outlook 2018* (AEO2018), whereas the screening-level analyses discussed in other chapters of this report assume that plants would generate approximately the same quantity of electricity in 2020 as they did on average during 2011-2016.

Changes in electricity production costs and potential associated changes in electricity output at steam electric power plants can have a range of broader market impacts that extend beyond the effect on steam electric power plants. In addition, the impact of compliance requirements on steam electric power plants may be seen differently when the analysis considers the impact on those plants in the context of the broader electricity market instead of looking at the impact on a standalone, single-plant basis. Therefore, use of a comprehensive, market model analysis system that accounts for interdependence of electric generating units is important in assessing regulatory impacts on the electric power industry as a whole.

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29 For more information on IPM, see https://www.epa.gov/airmarkets/clean-air-markets-power-sector-modeling. The version of IPM used for this analysis incorporate the effects of the December 2017 tax law which reduced corporate tax rates from 35 percent to 21 percent, along with other changes (see U.S. EPA, 2018b).

30 For the 2015 rule analysis, the EPA used IPM to inform assessment of the economic achievability of the ELG options under CWA Sections 301(b)(2)(A) and 304(b)(2) (see U.S. EPA, 2015b).

The EPA's use of IPM V6 for this analysis is consistent with the intended use of the model to evaluate the effects of changes in electricity production costs, on electricity generation costs, subject to specified demand and emissions constraints. As discussed in greater detail in U.S. EPA (2018a), IPM generates least-cost resource dispatch decisions based on user-specified constraints such as environmental, demand, and other operational constraints. The model can be used to analyze a wide range of electric power market scenarios at the plant, regional, and national levels. Applications of IPM have included capacity planning, environmental policy analysis and compliance planning, wholesale price forecasting, and asset valuation.

IPM uses a long-term dynamic linear programming framework that simulates the dispatch of generating capacity to achieve a demand-supply equilibrium on a seasonal basis and by region. The model computes optimal capacity that combines short-term dispatch decisions with long-term investment decisions. Specifically, IPM seeks the optimal solution to an "objective function," which is the summation of all the costs incurred by the electric power sector, *i.e.*, capital costs, fixed and variable operation and maintenance (O&M) costs, and fuel costs, on a net present value basis over the entire evaluated time horizon. The objective function is minimized subject to a series of supply and demand constraints. Supply-side constraints include capacity constraints, availability of generation resources, plant minimum operating constraints, transmission constraints, fuel supply constraints, and environmental constraints. Demand-side constraints include reserve margin constraints and minimum system-wide load requirements.

The final difference between the EPA's electricity market optimization model analysis and the screening-level analyses in *Chapter 4: Cost and Economic Impact Screening Analyses* is the inclusion of estimated market-level impacts of environmental rules in the analysis baseline. Notably, for this current proposal, the EPA started from an electricity market "base case" that includes market-level impacts of the Cross-State Air Pollution Rule (CSAPR and CSAPR Update), Mercury and Air Toxics Standards (MATS), CWA section 316(b) rule, and the final CCR rule, among others. The base case includes the effects of the Regional Greenhouse Gas Initiative (RGGI) and California's Global Warming Solutions Act, but excludes the federal Clean Power Plan (CPP) given ongoing litigation, a Supreme Court stay, and regulatory review.[31] The EPA also conducted a sensitivity analysis of proposed Option 2 that includes market-level impacts of the ACE rule finalized in June 19, 2019 (see Section 2.2.1). Appendix C summarize the results of this sensitivity analysis.

In analyzing the effect of the regulatory options using IPM V6, the EPA first specified a base case that incorporates fixed and variable costs that are estimated to be incurred by steam electric power plants and generating units to comply with the 2015 rule requirements for fly ash transport water, bottom ash transport water, and FGD wastewater (in the IPM documentation, these costs are referred to as "FOM and VOM adders" and correspond to fixed O&M [FOM] and variable O&M [VOM]). Results for this first model run provide the baseline against which to compare outputs for regulatory options runs. In analyzing Options 2 and 4, the EPA modified the associated fixed and variable costs to reflect the difference between the bottom ash transport water and FGD wastewater compliance costs under the 2015 rule and those for the regulatory options in this proposal. The EPA ran IPM to simulate the dispatch of electricity

[31] On October 16, 2017, the EPA proposed to repeal the Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units (EGUs), (82 FR 48035).

generating units that would meet projected demand at the lowest costs subject to the same constraints as those present in the analysis baseline.

The rest of this chapter is organized as follows:

- Section 5.1 summarizes the key inputs to IPM for performing the analyses of the regulatory options and the key outputs reviewed as indicators of the effect of the regulatory options.
- Section 5.2 provides the findings from the market model analysis.
- Section 5.3 discusses the effects of the regulatory options on new coal capacity.
- Section 5.4 identifies key uncertainties and limitations in the market model analysis.

5.1 Model Analysis Inputs and Outputs

To assess the impact of the regulatory options, the EPA compared each of two policy runs (Option 2 and Option 4) to an IPM V6 Base Case projection of electricity markets and plant operations that includes the modeled effects of the 2015 rule, among existing environmental regulations.

5.1.1 Analysis Years

As described in U.S. EPA (2018a), IPM V6 models the electric power market over the 34-year period from 2021 to 2054, breaking this period into the eight representative run years shown in Table 5-1. As discussed in *Chapter 1* steam electric power plants are estimated to implement control technologies to meet the regulatory option requirements starting in 2021 and as late as 2028. This technology implementation window primarily falls within the time periods captured by the 2021, 2023 and 2025 run years (*i.e.*, 2021-2027). The 2030 run year includes the last year of technology implementation, 2028, and goes through 2032.

Table 5-1: IPM Run Years

Run Year	Years Represented
2021	2021
2023	2022-2023
2025	2024-2027
2030	2028-2032
2035	2033-2037
2040	2038-2042
2045	2043-2047
2050	2048-2054

Source: U.S. EPA, 2018a.

To assess the effect of the regulatory options on electricity markets during the period *after* technology implementation by *all* steam electric power plants – the *steady state* post-compliance period – the EPA analyzed results reported for the IPM 2030 run year.[32] As discussed in *Chapter 3*, under the regulatory

[32] Although all run years are reported in the IPM results, for the 2015 rule the EPA focused on two run years to cover the range of potentially significant changes: one run year representing the period when plants would be in the process of

option specifications considered for this analysis, this *steady state* period is estimated to begin in the last year of the technology implementation window, *i.e.*, 2028, and continue into the future. The 2028 analysis year is captured in the IPM 2030 run year. Because the model run year 2030, captures mostly calendar years (*i.e.*, 2028-2033) that fall outside the technology implementation window of 2021 through 2028, the EPA determined that 2030 is an appropriate run year to capture steady-state regulatory effects. Plants that implement changes in 2028 will have begun planning prior to this year, such that the period covers years that reflect full implementation of the rule. Effects that may occur during the post-compliance "steady state" include potential *permanent* changes in generating capacity from changes in early retirement (closure) of generating units, *long-term* changes in electricity production costs due to changes in operating expenses, *permanent* changes in electric generating capability and production efficiency at steam electric power plants, and, as described above, changes in dispatches of other generating units resulting from the changes in electric generating capacity.

5.1.2 Key Inputs to IPM V6 for the Market Model Analysis of the Proposed ELG Revisions

5.1.2.1 Existing Plants

The inputs for the electricity market analyses include compliance costs and the technology implementation year. IPM models the entire electric power generating industry using a total of 18,742 generating units at 7,642 plants. The EPA estimated that up to 121 steam electric power plants may incur non-zero compliance costs under any of the regulatory options, based on the costing methodologies described in the *Supplemental TDD*; (U.S. EPA, 2019a).[33]

The EPA input the ELG capital, initial one-time costs, annual fixed O&M (FOM), and annual variable O&M (VOM) costs, as well as costs incurred on a non-annual, periodic basis (3-year, 5-year, 6-year, 10-year) into IPM as FOM and VOM cost adders. IPM modelers calculated the net present value of annualized costs using IPM's conventional framework for recognizing costs incurred over time, by assigning to each cost the same technology implementation years discussed in *Chapter 3*.[34]

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implementing technologies, and one run year falling after the compliance period. The regulatory options of this proposal were analyzed using the run year 2030 only because unlike the 2015 rule analysis, the impacts associated with these regulatory options were too small to warrant reporting based on two run years.

33 117 of these 121 plants are modeled in IPM. Coal generating units at the four remaining plants are not included in IPM, due to retirements (see *Chapter 2* for discussion of retirements). For example, one plant decommissioned its coal-fired generating units in 2018 in anticipation of repowering to natural gas combustion turbines and IPM therefore does not include these units. These retirements were not captured in updates to the universe of plants for which EPA estimated costs. The costs described earlier in Chapters 3 and 4 accordingly overstate compliance costs ultimately modeled in IPM. Estimated pre-tax compliance costs for the four plants omitted from IPM are $14.8 million under Option 4, or 3.6 percent of the total pre-tax costs for this option of $416.9 million. Omissions are smaller for Option 2, with omitted pre-tax compliance costs of $7.6 million, or 2.9 percent of the total pre-tax costs for this option of $266.8 million.

34 IPM seeks to minimize the total, discounted net present value, of the costs of meeting demand, accounting for power operation constraints, and environmental regulations over the entire planning horizon. These costs include the cost of any new plant, pollution control construction, fixed and variable operating and maintenance costs, and fuel costs. As described in the IPM documentation, "*Capital costs in IPM's objective function are represented as the net present value of levelized stream of annual capital outlays, not as a one-time total investment cost. The payment period used in calculating the levelized annual outlays never extends beyond the model's planning horizon: it is either the book life of the investment or the years remaining in the planning horizon, whichever is shorter. This approach avoids presenting artificially lower capital costs for investment decisions taken closer to the model's time horizon boundary simply because some of that cost would typically be serviced in years beyond the model's view. This treatment of capital costs*

5.1.2.2 New Capacity

The EPA did not specify ELG compliance costs for new coal capacity. IPM projections include new generating capacity as needed to meet demand. As described below, IPM projects no new coal capacity under the baseline or under the regulatory options.

5.1.3 Key Outputs of the Market Model Analysis Used in Assessing the Effects of the Regulatory Options

IPM generates a series of outputs at different levels of aggregation (model plant, region, and nation). For this analysis, the EPA used a subset of the available IPM output for each model run (base case and each analyzed regulatory option), focusing on metrics that quantify projected changes in capacity (including early retirements and new capacity), generation, production costs, electricity prices, and emissions. See Chapter 5 in the RIA document for the 2015 rule (U.S. EPA, 2015b) for descriptions of the IPM variables.

The EPA compared national-level outputs for selected IPM run years (2021, 2023, 2025, 2030, 2040, and 2050).[35] EPA then looked at changes in more detailed regional and plant-level outputs for the 2030 run year. Comparison of these outputs for the baseline and policy cases provides insight into the incremental effect of the regulatory options on steam electric power plants and the broader electric power markets.[36]

5.2 Findings from the Market Model Analysis

The impacts of the regulatory options are assessed as the difference between key economic and operational impact metrics that compare the results for the policy cases to the baseline case. This section presents two sets of analysis:

- *Analysis of national-level impacts*: The EPA compared baseline and policy IPM results reported for a series of run years to provide insight on the direction and magnitude of market-level changes attributable to the regulatory options over time.

- *Analysis of long-term regulatory impacts*: As discussed earlier, to assess the long-term impact of the regulatory options, the EPA compared baseline and policy IPM results reported for 2030. These results provide insight on the effect of the regulatory options both for the entire electricity market and for steam electric power plants specifically.

5.2.1 National-level Analysis Results for Model Years 2021-2050

Table 5-2 shows baseline values of total costs to electric power plants, wholesale electricity price, total existing capacity, new capacity, plant retirements, and generation mix at the national-level based on IPM results for the Base Case. The baseline projections show a progressive decline in total coal generation capacity during the period (from 176.4 GW in 2021 to 144.5 GW in 2050; 18 percent reduction) and nuclear generation capacity (17 percent reduction), and increases in generation capacity from renewables, natural gas, and other sources. These projections are consistent with the market trends discussed in Section 2.3. Table 5-3 provides incremental changes in these measures for Options 2 and 4, relative to the

ensures both realism and consistency in accounting for the full cost of each of the investment options in the model." (U.S. EPA, 2018a, page 2-7).

35 IPM also provides estimates for four additional run years: 2023, 2025, 2035, and 2045.

36 IPM output also includes total fuel usage, which is not part of the analysis discussed in this Chapter.

baseline (negative values represent decreases relative to the baseline). For conciseness, the tables show results for the years 2021, 2023, 2025, 2030, 2040, and 2050, but IPM V6 also provides projections for model years 2035 and 2045.

Table 5-2: Baseline Projections, 2021-2050

Economic Measures	Baseline					
	2021	2023	2025	2030	2040	2050
Total Costs						
Total Costs (million 2018$)	$135,820	$141,458	$145,980	$156,921	$179,174	$188,890
Prices						
National Wholesale Electricity Price (mills/kWh)	33.40	38.39	39.22	42.96	44.79	45.28
Total Capacity (Cumulative GW)						
Renewables[a]	290.3	302.5	321.1	376.8	383.3	435.2
Coal	176.4	172.3	171.8	169.9	161.5	144.5
Nuclear	88.4	82.4	81.3	76.6	75.4	73.3
Natural Gas	407.7	414.9	415.5	425.8	509.6	622.0
Oil/Gas Steam	71.3	71.5	71.7	71.7	71.3	67.2
Other	9.6	9.6	11.1	12.5	12.5	12.8
Grand Total	**1,043.7**	**1,053.3**	**1,072.6**	**1,133.3**	**1,213.7**	**1,355.1**
New Capacity (Cumulative GW)						
Renewables[a]	66.8	79.1	97.7	153.4	159.9	211.8
Coal	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0
Natural Gas	2.2	9.5	10.1	20.7	104.5	217.0
Other	2.5	2.5	4.0	5.4	5.4	5.7
Grand Total	**71.6**	**91.1**	**111.9**	**179.5**	**269.8**	**434.5**
Retirements (GW)[b]						
Combined Cycle Retirements	2.9	2.9	2.9	2.9	2.9	2.9
Coal Retirements	48.3	49.3	49.3	51.0	59.4	75.8
Combustion Turbine Retirements	1.6	1.6	1.6	1.9	1.9	1.9
Nuclear Retirements	3.9	11.1	12.2	17.0	18.1	20.2
Oil/Gas Retirements	6.0	6.0	5.9	6.0	6.3	10.5
Grand Total	**67.0**	**75.2**	**76.4**	**83.2**	**93.1**	**116.3**
Generation Mix (thousand GWh)						
Renewables[a]	842.6	872.2	906.6	1,056.3	1,076.2	1,252.8
Coal	867.1	914.5	919.1	882.2	790.4	716.5
Nuclear	694.3	651.5	642.7	604.0	596.6	579.4
Natural Gas	1,576.1	1,593.5	1,613.8	1,656.4	2,026.8	2,303.3
Oil/Gas Steam	62.9	60.4	60.8	56.9	43.9	15.7
Other	35.3	35.8	36.3	37.0	37.5	37.6
Grand Total	**4,078.4**	**4,127.8**	**4,179.2**	**4,292.8**	**4,571.3**	**4,905.2**

a. Renewables include hydropower and non-hydropower renewables.

b. There were no changes in projected retirements for IGCC, biomass, fuel cell, other fossil fuel, geothermal, hydropower, landfill gas, other non-fossil fuel, and energy storage plants.

Source: U.S. EPA Analysis, 2019

Table 5-3: National Impact of Regulatory Options Relative to Baseline, 2021-2050

Economic Measures	Option 2 Changes Relative to Baseline						Option 4 Changes Relative to Baseline					
	2021	2023	2025	2030	2040	2050	2021	2023	2025	2030	2040	2050
Total Costs												
Total Costs (million $)	-$193	-$260	-$187	-$140	-$53	$14	-$229	-$195	-$56	$4	$68	$24
Prices												
National Wholesale Electricity Price (mills/kWh)	-0.08	-0.04	-0.02	-0.05	-0.01	0.01	-0.08	0.02	-0.03	-0.05	0.01	0.01
Total Capacity (Cumulative GW)												
Renewables[a]	0.0	-1.1	-1.1	-0.4	-0.3	-0.4	0.0	-0.9	-0.9	-0.1	0.0	-0.3
Coal	1.2	1.2	1.2	1.1	0.7	0.8	0.8	0.8	0.8	0.7	0.4	0.9
Nuclear	0.0	0.0	0.0	-0.1	-0.1	-0.1	0.0	0.0	0.0	0.1	0.1	0.1
Natural Gas	0.0	0.0	0.1	-0.5	-0.3	-0.5	0.0	0.0	0.3	-0.5	-0.3	-0.9
Oil/Gas Steam	-0.2	-0.2	-0.2	-0.2	0.0	0.0	0.0	0.0	-0.1	-0.1	0.0	0.0
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Grand Total	**1.1**	**-0.1**	**0.0**	**0.0**	**-0.1**	**-0.2**	**0.8**	**-0.1**	**0.1**	**0.1**	**0.1**	**-0.2**
New Capacity (Cumulative GW)												
Renewables[a]	0.0	-1.1	-1.1	-0.4	-0.3	-0.4	0.0	-0.9	-0.9	-0.1	0.0	-0.3
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Natural Gas	0.0	-0.1	0.1	-0.6	-0.3	-0.5	0.0	0.0	0.3	-0.5	-0.3	-0.9
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Grand Total	**0.0**	**-1.2**	**-1.1**	**-0.9**	**-0.7**	**-0.9**	**0.0**	**-0.9**	**-0.6**	**-0.6**	**-0.4**	**-1.2**
Retirements (GW)[b]												
Combined Cycle Retirements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal Retirements	-1.2	-1.2	-1.2	-1.1	-0.7	-0.8	-0.8	-0.8	-0.8	-0.7	-0.4	-0.9
Combustion Turbine Retirements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear Retirements	0.0	0.0	0.0	0.1	0.1	0.1	0.0	0.0	0.0	-0.1	-0.1	-0.1
Oil/Gas Retirements	0.2	0.2	0.2	0.2	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0
Grand Total	**-1.1**	**-1.1**	**-1.1**	**-0.9**	**-0.6**	**-0.7**	**-0.8**	**-0.8**	**-0.8**	**-0.7**	**-0.5**	**-1.0**
Generation Mix (thousand GWh)												
Renewables[a]	-0.1	-1.9	-1.8	-0.9	-0.8	-0.5	0.0	-1.6	-1.5	-0.4	0.0	-0.4
Coal	1.6	2.4	2.2	4.9	1.8	0.9	0.6	1.9	-0.9	1.4	-0.7	-1.6
Nuclear	0.0	0.0	0.0	-0.7	-0.7	-0.7	0.0	0.0	0.0	0.7	0.7	0.7
Natural Gas	-1.1	-0.2	-0.1	-3.3	0.0	0.4	-0.2	-0.2	2.4	-1.8	0.1	1.4
Oil/Gas Steam	-0.2	-0.1	-0.3	0.1	0.0	0.1	-0.2	-0.1	0.0	0.2	0.0	0.2
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.1	0.0
Grand Total	**0.2**	**0.2**	**0.1**	**0.1**	**0.3**	**0.1**	**0.2**	**0.1**	**0.0**	**0.2**	**0.0**	**0.2**

a. Renewables include hydropower and non-hydropower renewables.

b. There were no changes in projected retirements for IGCC, biomass, fuel cell, other fossil fuel, geothermal, hydropower, landfill gas, other non-fossil fuel, and energy storage plants.

Source: U.S. EPA Analysis, 2019

5.2.1.1 Findings for Regulatory Option 2

Under Option 2, total costs to electric power plants are projected to be lower than the baseline from 2021 to around 2040. The reduction in costs is greatest in the early years of the modeling period (e.g., by $193.5 million in 2021), which is consistent with the timing of ELG implementation under the baseline and the regulatory options. By the end of the modeling period in 2050, costs are projected to increase by $13.6 million (0.01 percent of baseline costs). Similar to total costs relative to the baseline, IPM projects changes in wholesale electricity prices between 2021 and 2040 between 0.0 and 0.1 mills per kWh.

Looking at results for total capacity by energy source, coal capacity is estimated to increase for all years from 2021 to 2050 by 0.7 to 1.2 GW. The additional capacity under Option 2 is projected to come from avoided retirements of existing units. As is the case of the baseline, no new coal capacity is projected. Meanwhile, decreases in capacity from renewables, natural gas, and nuclear are estimated to occur from around 2030 to 2050. Capacity from renewables is estimated to decrease by 0.3 to 0.4 GW, and natural gas capacity is estimated to decrease by 0.3 to 0.5 GW, with both of these changes due to avoided new capacity additions. The reduction in nuclear capacity in 2030-2050, by contrast, is projected to result from incremental retirements of nuclear generation units, as they become relatively less economical to operate.

Avoided coal retirements are estimated for all years, ranging between 0.7 to 1.2 GW of the 1.8 GW estimated to retire in the baseline. This accounts for most of the avoided retirements in the electric market as a whole, which ranges between 0.6 to 1.1 GW.

Lastly, examining results for generation by energy source, generation from coal is estimated to increase from 2021 to 2050 by 0.9 to 4.9 GWh, offset in part by a decline in generation by renewables (0.1 to 0.9 GW reduction) and natural gas generation, which decreases from 2021 to 2030 by 1.1 to 3.3 GW, then increases after 2040 by 0.0 to 0.4.

5.2.1.2 Findings for Regulatory Option 4

Under Option 4, the reduction in total costs does not extend as long as under Option 2, which is consistent with the timing and magnitude of compliance expenditures for this option as compared to the baseline. Total costs for Option 4 decrease in 2021 by $228.6 million, then increase from 2030 to 2050 by $4.0 million to $67.8 million. The decrease in wholesale electricity prices is similar in magnitude ($0.0 to $0.1 per kWh) as Option 2, though it occurs for a shorter time period (2021-2030) before higher costs are incurred.

As for total capacity by energy source, coal capacity is estimated to increase for all years, similar to Option 2, but at lesser magnitudes of 0.4 to 0.9 GW. This increase is the result of avoided retirements (0.4 to 0.9 GW) since no new coal capacity is estimated under Option 4 from 2021-2030, and negligible new capacity is estimated afterwards. Balancing out the increase in coal capacity, capacity from renewables and natural gas are estimated to avoid 0.0 to 0.3 GW and 0.3 to 0.9 GW of new capacity between 2030 and 2050, respectively. For renewables, the decline is uniformly less than under Option 2 (0.0 to 0.3 GW between 2030 and 2050). Avoided new capacity from natural gas shows similar trends, except for 2050 when natural gas is estimated to have greater avoided new capacity of 0.9 GW.

Coal generation increases from 2021-2030 by 0.6 to 1.4 GWh then decreases from 2040 to 2050 by 0.7 to 1.6 GWh. This is offset by a reduction in generation from renewables in all years by 0.0-0.4 GWh, and from natural gas from 2021 to 2030 by 0.2 to 1.8 GW, although natural gas then increases after 2040 by 0.1 to 1.4 GWh.

5.2.2 Detailed Analysis Results for Model Year 2030

In the following results which reflect conditions in the period of 2028 through 2033, all plants are estimated to meet the revised BAT limits and pretreatment standards associated with each analyzed regulatory options. For this more detailed analysis, following the approach used for the 2015 rule (U.S. EPA, 2015b), the EPA used parsed IPM outputs and considered impact metrics of interest at three levels of aggregation:

- Impact on national and regional electricity markets (Section 5.2.2.1),
- Impact on steam electric power plants as a group (Section 5.2.2.2), and
- Impact on individual steam electric power plants (Section 5.2.2.3).

5.2.2.1 Impact on National and Regional Electricity Markets

The market-level analysis assesses national and regional changes as a result of the regulatory requirements. The EPA analyzed six measures:

- *Changes in available capacity*: This measure analyzes changes in the nameplate capacity available to generate electricity. A long-term reduction in available capacity may result from partial or full closures of steam electric power plants. Conversely, increased capacity may result from *avoided* partial or full closure of the plants or the addition of new capacity. Only capacity that is projected to remain operational in the baseline case but is closed in the policy case is considered a closure attributable to the regulatory option. The Market Model Analysis may project partial (*i.e.*, unit) or full plant early retirements (closures) for a given regulatory option. It may also project partial or full avoided closures in which a unit or plant that is estimated to close in the baseline is estimated to continue operation in the policy case. Avoided closures may occur, in particular, when the option results in lower costs for a given plant.
- *Changes in the wholesale price of electricity*: This measure represents the change in the annual average energy price (the marginal cost of meeting demand in each time segment, averaged annually) plus any capacity prices associated with maintaining a reserve margin. In the long term, electricity prices may change as a result of changes in generation costs at steam electric power plants or due to generating unit and/or plant closures.
- *Changes in generation*: This measure considers the amount of electricity generated. At a regional level, long-term changes in generation may result from plant closures or a change in the amount of electricity traded between regions. At the national level, the demand for electricity does not change between the baseline and the analyzed policy options (generation within the regions is allowed to vary) because meeting demand is an exogenous constraint imposed by the model. However, demand for electricity does vary across the modeling horizon according to the model's underlying electricity demand growth assumptions.

- *Changes in costs*: This measure considers changes in the overall cost of generating electricity, including fuel costs, variable and fixed O&M costs, and capital costs. These costs are not limited to steam electric generating units or to compliance costs of the regulatory options, but more broadly reflect changes in the cost of generating electricity across all units. Fuel costs and variable O&M costs are production costs that vary with the level of generation. Fuel costs generally account for the single largest share of production costs. Fixed O&M costs and capital costs do not vary with generation. They are fixed in the short-term and therefore do not affect the dispatch decision of a unit (given sufficient demand, a unit will dispatch as long as the price of electricity is at least equal to its per MWh production costs). However, in the long-run, these costs need to be recovered for a unit to remain economically viable.

- *Changes in variable production costs per MWh*: This measure considers the change in average variable production cost per MWh. Variable production costs are a subset of the costs in the bullet above and include fuel costs and other variable O&M costs but exclude fixed O&M costs and capital costs. Production cost per MWh is a primary determinant of how often a generating unit is dispatched. This measure presents similar information to total fuel and variable O&M costs, but normalized for changes in generation.

- *Changes in CO_2, NOx, SO_2, Hg, and HCL emissions*: This measure considers the change in emissions resulting from electricity generation, for example due to changes in the fuel mix. Compliance with the regulatory options is estimated to reduce generation costs when compared to the baseline and make electricity generated by some steam electric units less expensive compared to that generated at other steam electric or non-steam electric units. These changes may in turn result in changes in air pollutant emissions, depending on the emissions profile of dispatched units. Projected changes in air emissions are used as inputs for the analysis of air-related benefits of the regulatory options (see Chapter 7 in the BCA document [U.S. EPA, 2019b]).

Table 5-4 summarizes IPM results for regulatory options at the level of the national market and also for regional electricity markets defined on the basis of NERC regions. All of the impact metrics described above are reported at both the national and NERC level except electricity prices, which are calculated in IPM only at the regional level (*i.e.*, not aggregated to national level). Differences in the relative magnitude of impacts across the NERC regions largely reflect regional differences in compliance costs for the regulatory options as compared to the baseline (*i.e.*, number of plants incurring costs and the magnitude of these costs) and the generation mix.

Table 5-4: Impact of Regulatory Options on National and Regional Markets at the Year 2030

Economic Measures (all dollar values in 2018$)	Baseline Value	Option 2			Option 4		
		Value	Difference	% Change	Value	Difference	% Change
National Totals							
Total Domestic Capacity (GW)	1,142	1,143	0.6	0.1%	1,144	1.4	0.1%
Existing			1.5	0.1%		2.0	0.2%
New Additions			-0.9	-0.1%		-0.6	-0.1%
Early Retirements			-1.5	-0.14%		-2.0	-0.2%
Wholesale Price ($/MWh)	$42.96	$42.90	-$0.05	-0.1%	$42.91	-$0.05	-0.1%
Generation (TWh)	4,286	4,287	0.1	0.0%	4,287	0.2	0.0%

Table 5-4: Impact of Regulatory Options on National and Regional Markets at the Year 2030

Economic Measures (all dollar values in 2018$)	Baseline Value	Option 2 Value	Option 2 Difference	Option 2 % Change	Option 4 Value	Option 4 Difference	Option 4 % Change
Costs ($Millions)	$156,921	$156,781	-$140	-0.1%	$156,925	$4	0.0%
Fuel Cost	$69,971	$70,028	$57	0.1%	$69,991	$20	0.0%
Variable O&M	$10,261	$10,263	$2	0.0%	$10,307	$47	0.5%
Fixed O&M	$52,916	$52,834	-$82	-0.2%	$52,933	$17	0.0%
Capital Cost	$23,774	$23,657	-$117	-0.5%	$23,694	-$79	-0.3%
Variable Production Cost ($/MWh)	$18.72	$18.73	$0.01	0.1%	$18.73	$0.01	0.1%
CO2 Emissions (Million Metric Tons)	1,581	1,585	3.9	0.2%	1,582	1.2	0.1%
Mercury Emissions (Tons)	4	4	0.0	0.4%	4	0.0	0.1%
NOx Emissions (Million Tons)	1	1	0.0	0.5%	1	0.0	0.1%
SO2 Emissions (Million Tons)	1	1	0.0	0.6%	1	0.0	0.2%
HCL Emissions (Million Tons)	0	0	0.0	0.5%	0	0.0	0.1%
Florida Reliability Coordinating Council (FRCC)							
Total Domestic Capacity (GW)	59	59	0.0	0.0%	59	0.0	-0.1%
Existing			0.0	0.0%		0.0	0.0%
New Additions			0.0	0.0%		0.0	-0.1%
Early Retirements			0.0	0.0%		0.0	0.0%
Wholesale Price ($/MWh)	$46.41	$46.41	$0.00	0.0%	$46.42	$0.01	0.0%
Generation (TWh)	256	256	0	0.0%	256	0	-0.1%
Costs ($Millions)	$10,411	$10,404	-$7	-0.1%	$10,409	-$2	0.0%
Fuel Cost	$6,662	$6,661	-$1	0.0%	$6,659	-$3	0.0%
Variable O&M	$605	$605	$0	0.1%	$608	$4	0.6%
Fixed O&M	$2,643	$2,638	-$4	-0.2%	$2,646	$3	0.1%
Capital Cost	$502	$499	-$3	-0.6%	$496	-$5	-1.1%
Variable Production Cost ($/MWh)	$28.39	$28.40	$0.01	0.0%	$28.42	$0.02	0.1%
CO2 Emissions (Million Metric Tons)	97	97	-0.1	-0.1%	97	-0.1	-0.1%
Mercury Emissions (Tons)	0	0	0.0	-0.1%	0	0.0	-0.1%
NOx Emissions (Million Tons)	0	0	0.0	0.0%	0	0.0	-0.1%
SO2 Emissions (Million Tons)	0	0	0.0	-0.7%	0	0.0	-1.2%
HCL Emissions (Million Tons)	0	0	0.0	-0.4%	0	0.0	-0.4%
Midwest Reliability Organization (MRO)							
Total Domestic Capacity (GW)	68	68	-0.1	-0.1%	68	-0.1	-0.1%
Existing			0.0	0.0%		0.0	0.0%
New Additions			-0.1	-0.1%		-0.1	-0.1%
Early Retirements			0.0	0.0%		0.0	0.0%
Wholesale Price ($/MWh)	$40.89	$40.76	-$0.13	-0.3%	$40.76	-$0.14	-0.3%
Generation (TWh)	272	272	0	0.1%	272	0	0.0%
Costs ($Millions)	$8,822	$8,821	-$2	0.0%	$8,826	$3	0.0%
Fuel Cost	$3,651	$3,659	$8	0.2%	$3,655	$4	0.1%
Variable O&M	$763	$761	-$2	-0.2%	$766	$3	0.4%
Fixed O&M	$2,890	$2,887	-$3	-0.1%	$2,892	$2	0.1%
Capital Cost	$1,518	$1,513	-$5	-0.3%	$1,513	-$5	-0.4%
Variable Production Cost ($/MWh)	$16.23	$16.24	$0.01	0.1%	$16.25	$0.02	0.1%
CO2 Emissions (Million Metric Tons)	134	134	0.4	0.3%	134	0.2	0.2%
Mercury Emissions (Tons)	0	0	0.0	0.3%	0	0.0	0.2%
NOx Emissions (Million Tons)	0	0	0.0	1.1%	0	0.0	0.1%

Table 5-4: Impact of Regulatory Options on National and Regional Markets at the Year 2030

Economic Measures (all dollar values in 2018$)	Baseline Value	Option 2			Option 4		
		Value	Difference	% Change	Value	Difference	% Change
SO2 Emissions (Million Tons)	0	0	0.0	0.7%	0	0.0	0.1%
HCL Emissions (Million Tons)	0	0	0.0	0.3%	0	0.0	0.2%
Northeast Power Coordinating Council (NPCC)							
Total Domestic Capacity (GW)	80	80	-0.1	-0.2%	80	0.0	0.0%
Existing			-0.1	-0.2%		0.0	0.0%
New Additions			0.0	0.0%		0.0	0.0%
Early Retirements			0.1	0.2%		0.0	0.0%
Wholesale Price ($/MWh)	$42.47	$42.48	$0.00	0.0%	$42.46	-$0.01	0.0%
Generation (TWh)	238	238	0	0.0%	238	0	0.0%
Costs ($Millions)	$9,840	$9,841	$1	0.0%	$9,842	$2	0.0%
Fuel Cost	$3,343	$3,345	$2	0.1%	$3,346	$2	0.1%
Variable O&M	$390	$391	$0	0.1%	$391	$0	0.1%
Fixed O&M	$3,748	$3,747	-$1	0.0%	$3,749	$0	0.0%
Capital Cost	$2,359	$2,358	-$1	0.0%	$2,358	-$1	0.0%
Variable Production Cost ($/MWh)	$15.67	$15.68	$0.01	0.0%	$15.68	$0.01	0.0%
CO2 Emissions (Million Metric Tons)	47	47	0.0	0.1%	47	0	0.1%
Mercury Emissions (Tons)	0	0	0.0	0.0%	0	0	0.0%
NOx Emissions (Million Tons)	0	0	0.0	0.0%	0	0	0.1%
SO2 Emissions (Million Tons)	0	0	0.0	0.0%	0	0	0.0%
HCL Emissions (Million Tons)	0	0	0.0	0.0%	0	0	0.0%
ReliabilityFirst Corporation (RFC)							
Total Domestic Capacity (GW)	223	223	-0.4	-0.2%	223	0.0	0.0%
Existing			0.0	0.0%		0.3	0.1%
New Additions			-0.5	-0.2%		-0.4	-0.2%
Early Retirements			0.0	0.0%		-0.3	-0.1%
Wholesale Price ($/MWh)	$41.07	$41.04	-$0.03	-0.1%	$41.07	-$0.01	0.0%
Generation (TWh)	928	927	-1	-0.1%	927	-1	-0.1%
Costs ($Millions)	$35,545	$35,434	-$111	-0.3%	$35,469	-$77	-0.2%
Fuel Cost	$15,878	$15,882	$3	0.0%	$15,850	-$28	-0.2%
Variable O&M	$2,470	$2,469	-$1	0.0%	$2,480	$11	0.4%
Fixed O&M	$12,112	$12,047	-$65	-0.5%	$12,088	-$25	-0.2%
Capital Cost	$5,085	$5,036	-$49	-1.0%	$5,050	-$35	-0.7%
Variable Production Cost ($/MWh)	$19.78	$19.80	$0.02	0.1%	$19.78	$0.01	0.0%
CO2 Emissions (Million Metric Tons)	404	405	0.9	0.2%	403	-1	-0.3%
Mercury Emissions (Tons)	1	1	0.0	0.5%	1	0	-0.4%
NOx Emissions (Million Tons)	0	0	0.0	0.1%	0	0	-0.4%
SO2 Emissions (Million Tons)	0	0	0.0	0.1%	0	0	-0.3%
HCL Emissions (Million Tons)	0	0	0.0	0.3%	0	0	-0.8%
Southeast Electric Reliability Council (SERC)							
Total Domestic Capacity (GW)	273	274	1.4	0.5%	275	1.6	0.6%
Existing			1.7	0.6%		1.7	0.6%
New Additions			-0.3	-0.1%		0.0	0.0%
Early Retirements			-1.7	-0.6%		-1.7	-0.6%
Wholesale Price ($/MWh)	$43.72	$43.56	-$0.16	-0.4%	$43.56	-$0.16	-0.4%
Generation (TWh)	1,132	1,133	1	0.1%	1,134	1	0.1%

Table 5-4: Impact of Regulatory Options on National and Regional Markets at the Year 2030

Economic Measures (all dollar values in 2018$)	Baseline Value	Option 2			Option 4		
		Value	Difference	% Change	Value	Difference	% Change
Costs ($Millions)	$43,758	$43,756	-$3	0.0%	$43,838	$79	0.2%
Fuel Cost	$21,512	$21,537	$25	0.1%	$21,536	$23	0.1%
Variable O&M	$2,684	$2,688	$4	0.2%	$2,712	$28	1.0%
Fixed O&M	$15,895	$15,901	$5	0.0%	$15,939	$43	0.3%
Capital Cost	$3,667	$3,630	-$37	-1.0%	$3,652	-$15	-0.4%
Variable Production Cost ($/MWh)	$21.37	$21.38	$0.01	0.0%	$21.39	$0.02	0.1%
CO2 Emissions (Million Metric Tons)	419	421	2.2	0.5%	421	2	0.5%
Mercury Emissions (Tons)	1	1	0.0	1.3%	1	0	0.9%
NOx Emissions (Million Tons)	0	0	0.0	1.1%	0	0	0.9%
SO2 Emissions (Million Tons)	0	0	0.0	0.9%	0	0	0.9%
HCL Emissions (Million Tons)	0	0	0.0	1.8%	0	0	1.6%
Southwest Power Pool (SPP)							
Total Domestic Capacity (GW)	79	79	-0.1	-0.1%	79	0.0	0.0%
Existing			0.0	0.0%		0.0	0.0%
New Additions			-0.1	-0.1%		0.0	0.0%
Early Retirements			0.0	0.0%		0.0	0.0%
Wholesale Price ($/MWh)	$40.81	$40.79	-$0.02	-0.1%	$40.77	-$0.04	-0.1%
Generation (TWh)	269	269	0	0.0%	269	0	0.0%
Costs ($Millions)	$8,476	$8,460	-$16	-0.2%	$8,473	-$3	0.0%
Fuel Cost	$4,135	$4,144	$9	0.2%	$4,135	$0	0.0%
Variable O&M	$765	$765	$1	0.1%	$766	$1	0.2%
Fixed O&M	$2,658	$2,647	-$10	-0.4%	$2,654	-$4	-0.2%
Capital Cost	$918	$903	-$15	-1.7%	$918	-$1	-0.1%
Variable Production Cost ($/MWh)	$18.22	$18.26	$0.04	0.2%	$18.22	$0.01	0.0%
CO2 Emissions (Million Metric Tons)	132	132	0.3	0.2%	132	0	0.0%
Mercury Emissions (Tons)	0	0	0.0	0.2%	0	0	0.0%
NOx Emissions (Million Tons)	0	0	0.0	0.3%	0	0	0.1%
SO2 Emissions (Million Tons)	0	0	0.0	0.1%	0	0	0.0%
HCL Emissions (Million Tons)	0	0	0.0	0.2%	0	0	0.0%
Electric Reliability Organization of Texas (TRE)							
Total Domestic Capacity (GW)	119	119	0.0	0.0%	119	-0.1	-0.1%
Existing			0.0	0.0%		0.0	0.0%
New Additions			0.0	0.0%		-0.1	-0.1%
Early Retirements			0.0	0.0%		0.0	0.0%
Wholesale Price ($/MWh)	$40.69	$40.69	$0.00	0.0%	$40.69	-$0.01	0.0%
Generation (TWh)	416	416	0	0.0%	416	0	0.0%
Costs ($Millions)	$14,535	$14,531	-$4	0.0%	$14,529	-$6	0.0%
Fuel Cost	$7,121	$7,127	$6	0.1%	$7,136	$15	0.2%
Variable O&M	$855	$856	$1	0.1%	$857	$1	0.2%
Fixed O&M	$4,690	$4,686	-$4	-0.1%	$4,685	-$5	-0.1%
Capital Cost	$1,869	$1,862	-$7	-0.4%	$1,852	-$17	-0.9%
Variable Production Cost ($/MWh)	$19.16	$19.17	$0.01	0.1%	$19.19	$0.04	0.2%
CO2 Emissions (Million Metric Tons)	149	149	0.1	0.1%	149	0	0.2%
Mercury Emissions (Tons)	0	0	0.0	0.1%	0	0	0.1%
NOx Emissions (Million Tons)	0	0	0.0	0.1%	0	0	0.2%

Table 5-4: Impact of Regulatory Options on National and Regional Markets at the Year 2030

Economic Measures (all dollar values in 2018$)	Baseline Value	Option 2			Option 4		
		Value	Difference	% Change	Value	Difference	% Change
SO2 Emissions (Million Tons)	0	0	0.0	2.8%	0	0	0.0%
HCL Emissions (Million Tons)	0	0	0.0	0.2%	0	0	0.1%
Western Electricity Coordinating Council (WECC)							
Total Domestic Capacity (GW)	241	241	0.0	0.0%	241	0.0	0.0%
Existing			0.0	0.0%		0.0	0.0%
New Additions			0.0	0.0%		0.0	0.0%
Early Retirements			0.0	0.0%		0.0	0.0%
Wholesale Price ($/MWh)	$46.53	$46.55	$0.02	0.0%	$46.53	$0.00	0.0%
Generation (TWh)	775	775	0	0.0%	775	0	0.0%
Costs ($Millions)	$25,533	$25,536	$3	0.0%	$25,540	$7	0.0%
Fuel Cost	$7,668	$7,673	$4	0.1%	$7,674	$6	0.1%
Variable O&M	$1,729	$1,728	-$1	-0.1%	$1,728	-$1	-0.1%
Fixed O&M	$8,279	$8,279	$0	0.0%	$8,282	$3	0.0%
Capital Cost	$7,857	$7,856	$0	0.0%	$7,856	$0	0.0%
Variable Production Cost ($/MWh)	$12.12	$12.13	$0.00	0.0%	$12.13	$0.01	0.0%
CO2 Emissions (Million Metric Tons)	199	199	0.0	0.0%	199	0	0.0%
Mercury Emissions (Tons)	1	1	0.0	0.0%	1	0	0.1%
NOx Emissions (Million Tons)	0	0	0.0	0.1%	0	0	0.0%
SO2 Emissions (Million Tons)	0	0	0.0	-0.1%	0	0	-0.1%
HCL Emissions (Million Tons)	0	0	0.0	0.0%	0	0	-0.1%

a. Numbers may not add up due to rounding.

Source: U.S. EPA Analysis, 2019

5.2.2.1.1 Findings for Regulatory Option 2

As reported in Table 5-4, the Market Model Analysis indicates that Option 2 would have small effects on the electricity market, relative to the baseline, on both a national and regional sub-market basis, in the year 2030.

At the national level, total annual costs decrease by an estimated $140 million (approximately 0.1 percent) relative to baseline. Total costs in the RFC region decline by the largest amount, $111 million (0.3 percent), followed by the SPCC region with decreases of $16 million (0.2 percent); changes in estimated total annual costs in the other regions range between savings of $7 million (FRCC) to increases of $3 million (WECC). Overall at the national level, the net change in total capacity, including increases in existing capacity (which includes avoided early retirements) and reductions in new plants/units, is an increase of approximately 0.6 GW in capacity, which is about 0.1 percent of total market capacity. Although effects differ geographically, Option 2 is estimated to have minimal effect on capacity availability and supply reliability at the national level. Thus, the net capacity increase is a result of a gain in capacity in the SERC region of about 1.4 GW (0.5 percent of SERC region capacity) due to a combination of avoided early retirements and reduced new capacity additions, as well as losses in capacity in the MRO, NPCC, RFC, and SPP totaling about 0.7 GW (ranging between 0.1 and 0.2 percent of their regional capacities). The net losses in the MRO, RFC, and SPP regions are primarily due to the avoided addition of new capacity. Overall impacts on wholesale electricity prices are similarly minimal. Wholesale electricity prices are estimated to increase in some NERC regions, and fall in others. Price changes in individual regions range from -$0.16 per MWh (-0.4 percent) in SERC to $0.02 per MWh (less than 0.1 percent) in WECC. Finally, at the national level, total costs decrease by approximately 0.1 percent. Total costs are estimated to decrease most in RFC, by 0.3 percent.

At the national level, there are increases in emissions among all air pollutants modeled. NOx emissions increase by 0.5 percent; SO_2 emissions increase by 0.6 percent; CO_2 emissions increase by 0.2 percent, mercury emissions increase by 0.4 percent; and HCL emissions increase by 0.5 percent. The impact on emissions varies across regions and by pollutant. Emissions increase in some and decrease in other NERC regions.[37]

5.2.2.1.2 Findings for Regulatory Option 4

Similar to the results for Option 2, Option 4 has small effects on the electricity market, on both a national and regional sub-market basis, in the year 2030, despite higher compliance costs than under Option 2.

At the national level, total annual costs increase by $4 million (less than 0.1 percent) relative to baseline. Most regions do not experience much change in costs, but total costs in RFC decrease by $77 million (0.2 percent) while total costs in SERC increase by $79 million (0.2 percent). The net increase in total capacity under Option 4 is 1.4 GW (0.1 percent of total market capacity). This increase is driven mainly by the increase in capacity in SERC of 1.6 GW (0.6 percent of regional capacity), due to avoided retirements. There are decreases in capacity of 0.1 GW in MRO (0.1 percent of regional capacity) and 0.1 GW in TRE (0.1 percent of regional capacity). Overall impact on wholesale electricity prices are also small across NERC regions, with price changes ranging from -$0.16 per MWh (-0.1 percent) in SERC to $0.01 per MWh (less than 0.1 percent) in FRCC.

The increase in emissions at the national level is smaller than under Option 2. NOx, CO_2, mercury, and HCL emissions all increase by 0.1 percent, and SO_2 emissions increase by 0.2 percent. The impact on emissions varies across regions and pollutants. Emissions increase in some and decrease in other NERC regions.[37]

5.2.2.2 Impact on Steam Electric Power Plants as a Group

For the analysis of impact on steam electric power plants as a group, the EPA used the same IPM V6 results for 2030 used above to analyze the impact on national and regional electricity markets; however, this analysis considers the effect of the regulatory options on the subset of plants to which the ELGs apply, *i.e.*, steam electric power plants. The purpose of the previously described electricity market-level analysis is to assess the impact of the options analyzed in support of the regulatory options on the entire electric power sector, *i.e.*, including generators such as combustion turbines, wind or solar to which the ELGs do not apply. By contrast, the purpose of this analysis is to assess the impact of the regulatory options specifically on steam electric power plants. The analysis results for the group of steam electric power plants overall show a slightly greater impact on a percentage basis than that observed over *all* generating units in the IPM universe (*i.e.*, market-level analysis discussed in the preceding section [*Impact on National and Regional Electricity Markets*]); this is because, at the market level, impacts on

[37] The changes in emissions only accounts for changes in the profile of electricity generation, and do not include emissions associated with transportation or auxiliary power, which EPA analyzed separately (see *Supplemental TDD* for details).

steam electric units are offset by changes in capacity and energy production in the non-steam electric units.

The metrics of interest are largely the same as those presented above in assessing the effect of the regulatory options for the aggregate of the 686 steam electric power plants explicitly represented in IPM (as opposed to additional steam electric power plants that were not surveyed by EPA in the Steam Electric Survey[see U.S. EPA, 2015b]). In addition, a few measures differ: (1) new market-wide capacity additions and prices are not relevant at the level of steam electric power plants, (2) changes in emissions at only the 686 steam electric power plants provide incomplete insight for the overall estimated effect of the rule on emissions and are therefore not presented, and (3) the number of steam electric power plants with projected closure (or avoided closure) is presented.

The following four measures are reported in the analysis of steam electric power plants as a group. In all instances, the measures are tabulated for 686 steam electric power plants explicitly included in the EPA's Steam Electric Survey and analyzed in the Market Model Analysis (note that steam electric power plants not included in the tabulation incur no compliance costs for the options the EPA analyzed in IPM):

- *Changes in available capacity*: These changes are defined in the same way as in the preceding section (Impact on National and Regional Electricity Markets), with the exception of the units used (MW).

- *Changes in generation*: Long-term changes in generation may result from either changes in available capacity (see discussion above) or in the dispatch of a plant due to changes in production cost resulting from compliance response.

- *Changes in costs*: These changes are defined in the same way as in the preceding section (Impact on National and Regional Electricity Markets).

- *Changes in variable production costs per MWh*: These changes are defined in the same way as in the preceding section (Impact on National and Regional Electricity Markets).

Table 5-5 reports results of the Market Impact Analysis for steam electric power plants, as a group.

The impacts of the regulatory options on steam electric power plants differ from the total market impacts as these plants become more competitive compared to plants that see no savings under the regulatory options. As a result, capacity and generation impacts are greater for this set of plants than for the entire electricity market, relative to the baseline, but absolute differences are still small. As described above for the market-level analysis, those impacts vary across the NERC regions.

Table 5-5: Impact of Regulatory Options on In-Scope Plants, as a Group, at the Year 2030[a]

Economic Measures (all dollar values in 2018$)	Baseline Value	Option 2			Option 4		
		Value	Difference	% Change	Value	Difference	% Change
National Totals							
Total Domestic Capacity (MW)	336,872	339,752	2,880	0.9%	340,066	3,194	0.9%
Early Retirements - Number of Plants	79	79	0	0.0%	78	-1	-1.3%

Table 5-5: Impact of Regulatory Options on In-Scope Plants, as a Group, at the Year 2030[a]

Economic Measures (all dollar values in 2018$)	Baseline Value	Option 2			Option 4		
		Value	Difference	% Change	Value	Difference	% Change
Full & Partial Retirements - Capacity (MW)	58,192	55,312	-2,880	-4.9%	54,998	-3,194	-5.5%
Generation (GWh)	1,570,513	1,575,189	4,676	0.3%	1,571,747	1,235	0.1%
Costs ($Millions)	$60,298	$60,397	$98	0.2%	$60,401	$103	0.2%
Fuel Cost	$34,842	$34,976	$134	0.4%	$34,893	$51	0.1%
Variable O&M	$5,987	$5,999	$12	0.2%	$6,040	$52	0.9%
Fixed O&M	$19,165	$19,117	-$48	-0.3%	$19,166	$1	0.0%
Capital Cost	$304	$304	$0	0.1%	$303	-$1	-0.3%
Variable Production Cost ($/MWh)	$26.00	$26.01	$0.02	0.1%	$26.04	$0.05	0.2%
Florida Reliability Coordinating Council (FRCC)							
Total Domestic Capacity (MW)	27,584	27,584	0	0.0%	27,584	0	0.0%
Early Retirements - Number of Plants	1	1	0	0.0%	1	0	0.0%
Full & Partial Retirements - Capacity (MW)	869	869	0	0.0%	869	0	0.0%
Generation (GWh)	126,731	126,692	-39	0.0%	126,676	-55	0.0%
Costs ($Millions)	$5,271	$5,266	-$5	-0.1%	$5,276	$5	0.1%
Fuel Cost	$3,631	$3,630	-$1	0.0%	$3,630	-$1	0.0%
Variable O&M	$317	$317	$0	0.0%	$320	$3	1.0%
Fixed O&M	$1,323	$1,319	-$4	-0.3%	$1,326	$3	0.2%
Capital Cost	$0	$0	$0	NA	$0	$0	NA
Variable Production Cost ($/MWh)	$31.15	$31.15	$0.00	0.0%	$31.18	$0.03	0.1%
Midwest Reliability Organization (MRO)							
Total Domestic Capacity (MW)	24,324	24,324	0	0.0%	24,324	0	0.0%
Early Retirements - Number of Plants	7	7	0	0.0%	7	0	0.0%
Full & Partial Retirements - Capacity (MW)	4,402	4,402	0	0.0%	4,402	0	0.0%
Generation (GWh)	139,319	139,622	303	0.2%	139,474	155	0.1%
Costs ($Millions)	$4,828	$4,832	$4	0.1%	$4,837	$9	0.2%
Fuel Cost	$2,760	$2,768	$8	0.3%	$2,764	$4	0.2%
Variable O&M	$647	$645	-$2	-0.3%	$650	$3	0.5%
Fixed O&M	$1,345	$1,343	-$3	-0.2%	$1,347	$2	0.2%
Capital Cost	$76	$76	$0	0.0%	$76	$0	-0.3%
Variable Production Cost ($/MWh)	$24.45	$24.45	-$0.01	0.0%	$24.48	$0.02	0.1%
Northeast Power Coordinating Council (NPCC)							
Total Domestic Capacity (MW)	11,120	11,120	0	0.0%	11,120	0	0.0%
Early Retirements - Number of Plants	3	3	0	0.0%	3	0	0.0%
Full & Partial Retirements - Capacity (MW)	2,708	2,708	0	0.0%	2,708	0	0.0%
Generation (GWh)	27,573	27,606	34	0.1%	27,614	41	0.1%

Table 5-5: Impact of Regulatory Options on In-Scope Plants, as a Group, at the Year 2030[a]							
Economic Measures (all dollar values in 2018$)	**Baseline Value**	**Option 2**			**Option 4**		
		Value	**Difference**	**% Change**	**Value**	**Difference**	**% Change**
Costs ($Millions)	$1,309	$1,310	$1	0.1%	$1,311	$1	0.1%
Fuel Cost	$608	$609	$1	0.1%	$609	$1	0.1%
Variable O&M	$43	$43	$0	0.1%	$43	$0	0.2%
Fixed O&M	$658	$658	$0	0.0%	$658	$0	0.1%
Capital Cost	$0	$0	$0	NA	$0	$0	NA
Variable Production Cost ($/MWh)	$23.62	$23.63	$0.00	0.0%	$23.62	$0.00	0.0%
ReliabilityFirst Corporation (RFC)							
Total Domestic Capacity (MW)	76,002	76,016	14	0.0%	76,330	328	0.4%
Early Retirements - Number of Plants	35	36	1	2.9%	35	0	0.0%
Full & Partial Retirements - Capacity (MW)	21,956	21,942	-14	-0.1%	21,628	-328	-1.5%
Generation (GWh)	364,667	365,423	756	0.2%	362,764	-1,903	-0.5%
Costs ($Millions)	$13,982	$13,951	-$30	-0.2%	$13,894	-$87	-0.6%
Fuel Cost	$8,038	$8,046	$8	0.1%	$7,983	-$54	-0.7%
Variable O&M	$1,606	$1,605	-$1	-0.1%	$1,614	$8	0.5%
Fixed O&M	$4,304	$4,265	-$38	-0.9%	$4,262	-$42	-1.0%
Capital Cost	$35	$36	$1	2.8%	$35	$1	2.1%
Variable Production Cost ($/MWh)	$26.44	$26.41	-$0.04	-0.1%	$26.45	$0.01	0.0%
Southeast Electric Reliability Council (SERC)							
Total Domestic Capacity (MW)	103,935	106,801	2,866	2.8%	106,801	2,866	2.8%
Early Retirements - Number of Plants	17	16	-1	-5.9%	16	-1	-5.9%
Full & Partial Retirements - Capacity (MW)	20,836	17,970	-2,866	-13.8%	17,970	-2,866	-13.8%
Generation (GWh)	479,646	482,880	3,235	0.7%	482,597	2,952	0.6%
Costs ($Millions)	$19,139	$19,265	$126	0.7%	$19,313	$173	0.9%
Fuel Cost	$11,129	$11,232	$103	0.9%	$11,222	$93	0.8%
Variable O&M	$1,630	$1,646	$15	0.9%	$1,668	$38	2.3%
Fixed O&M	$6,313	$6,320	$7	0.1%	$6,355	$42	0.7%
Capital Cost	$67	$67	$0	0.0%	$67	$0	0.0%
Variable Production Cost ($/MWh)	$26.60	$26.67	$0.07	0.3%	$26.71	$0.11	0.4%
Southwest Power Pool (SPP)							
Total Domestic Capacity (MW)	26,885	26,885	0	0.0%	26,885	0	0.0%
Early Retirements - Number of Plants	3	3	0	0.0%	3	0	0.0%
Full & Partial Retirements - Capacity (MW)	1,879	1,879	0	0.0%	1,879	0	0.0%
Generation (GWh)	116,430	116,717	288	0.2%	116,338	-91	-0.1%

Table 5-5: Impact of Regulatory Options on In-Scope Plants, as a Group, at the Year 2030[a]							
Economic Measures	**Baseline**	**Option 2**			**Option 4**		
(all dollar values in 2018$)	**Value**	**Value**	**Difference**	**% Change**	**Value**	**Difference**	**% Change**
Costs ($Millions)	$4,394	$4,395	$1	0.0%	$4,388	-$6	-0.1%
Fuel Cost	$2,635	$2,642	$7	0.3%	$2,633	-$3	-0.1%
Variable O&M	$582	$582	$0	0.1%	$583	$1	0.1%
Fixed O&M	$1,163	$1,156	-$6	-0.5%	$1,158	-$4	-0.4%
Capital Cost	$15	$15	$0	0.4%	$14	$0	-1.1%
Variable Production Cost ($/MWh)	$27.63	$27.63	$0.00	0.0%	$27.64	$0.01	0.0%
Texas Regional Entity (TRE)							
Total Domestic Capacity (MW)	25,945	25,945	0	0.0%	25,945	0	0.0%
Early Retirements - Number of Plants	1	1	0	0.0%	1	0	0.0%
Full & Partial Retirements - Capacity (MW)	391	391	0	0.0%	391	0	0.0%
Generation (GWh)	114,229	114,369	140	0.1%	114,411	183	0.2%
Costs ($Millions)	$4,497	$4,498	$1	0.0%	$4,501	$3	0.1%
Fuel Cost	$2,499	$2,504	$4	0.2%	$2,506	$6	0.2%
Variable O&M	$441	$441	$1	0.1%	$442	$1	0.1%
Fixed O&M	$1,557	$1,553	-$3	-0.2%	$1,553	-$3	-0.2%
Capital Cost	$0	$0	$0	NA	$0	$0	NA
Variable Production Cost ($/MWh)	$25.74	$25.75	$0.01	0.0%	$25.76	$0.02	0.1%
Western Electricity Coordinating Council (WECC)							
Total Domestic Capacity (MW)	41,077	41,077	0	0.0%	41,077	0	0.0%
Early Retirements - Number of Plants	12	12	0	0.0%	12	0	0.0%
Full & Partial Retirements - Capacity (MW)	5,151	5,151	0	0.0%	5,151	0	0.0%
Generation (GWh)	201,919	201,879	-40	0.0%	201,872	-47	0.0%
Costs ($Millions)	$6,877	$6,878	$1	0.0%	$6,882	$5	0.1%
Fuel Cost	$3,541	$3,545	$4	0.1%	$3,547	$5	0.2%
Variable O&M	$721	$720	-$1	-0.2%	$720	-$1	-0.1%
Fixed O&M	$2,502	$2,502	$0	0.0%	$2,504	$2	0.1%
Capital Cost	$112	$111	-$1	-0.6%	$110	-$1	-1.2%
Variable Production Cost ($/MWh)	$21.11	$21.13	$0.01	0.1%	$21.14	$0.03	0.1%

a. Numbers may not add up due to rounding.

Source: U.S. EPA Analysis, 2019.

5.2.2.2.1 Findings for Regulatory Option 2 in the 2030 Model Year

Under Option 2, the magnitude of the net increase in steam electric capacity is greater than the capacity increase for the electricity market as a whole, although the change in capacity for the group of steam electric power plants is still small at less than one percent.

For the group of steam electric power plants, total capacity increases by 2,880 MW or approximately 0.9 percent of the 336,872 MW in baseline capacity. This increase is almost entirely attributable to avoided retirements in the SERC region of 2,866 MW (13.8 percent), and also avoided retirements in RFC of 14 MW (0.1 percent). RFC is the only region where a plant is projected to close under Option 2 (though this impact is indirectly the result of the regulatory option since the affected plant does not incur ELG compliance costs under this option), and one plant in SERC is estimated to avoid a full retirement, resulting in no net change in early full retirements at the national level.

The change in total generation is an indicator of how steam electric power plants fare, relative to the rest of the electricity market. While at the market level there is essentially no projected change in total electricity generation,[38] for steam electric power plants, total generation is estimated to increase by 4,676 GWh (0.3 percent). SERC is projected to experience the largest increase in generation, 3,235 GWh (0.7 percent), while MRO, NPCC, RFC, SPP, and TRE are estimated to experience increases of 0.1 to 0.2 percent. FRCC and WECC are projected to experience negligible decreases in generation.

Unlike the results for the whole electricity market, where total costs are estimated to decrease under Option 2 at the national level, the results for the group of steam electric power plants show a net increase in total costs of $98 million (0.2 percent), which is estimated given the increase in electricity generated by the group of plants. Total costs in the regions also follow the increases in electricity generation with costs in SERC increasing the most, by $126 million (0.7 percent), MRO and NPCC experiencing smaller increases of 0.1 percent, and FRCC and RFC experiencing decreases of 0.1 and 0.2 percent respectively. At the national level, variable production costs for steam electric power plants increase by $0.02 per MWh (0.1 percent). Effects vary by region, with changes ranging from -$0.04 per MWh in RFC to $0.07 per MWh in SERC.

5.2.2.2.2 Findings for Regulatory Option 4 in the 2030 Model Year

Results at the national level for steam electric power plants under Option 4 show an increase in total capacity of 3,194 MW (0.9 percent), slightly higher than the increase under Option 2. Unlike under Option 2, no plants are estimated to undergo a full retirement in any region, while there is still one plant estimated to avoid retirement in SERC (same as under Option 2), resulting in the net avoided closure of one plant at the national level. This avoided closure combined with capacity from avoided partial retirements in SERC and RFC comprise the increase in capacity at the national level.

There is an increase in total generation at the national level under Option 4 of 1,235 GWh (0.1 percent), which is smaller in magnitude than the increase under Option 2. There is more variability across the regions in the changes in generation under Option 4 than Option 2. Total generation is projected to decrease by 1,903 GWh (0.5 percent) in RFC, whereas it is projected to increase by 2,952 GWh (0.6 percent) in SERC. SPP is also projected to experience a decrease in generation of 91 GWh (0.1 percent). MRO and NPCC are estimated to experience increases in generation of 0.1-0.2 percent. As in Option 2, FRCC and WECC are estimated to experience negligible declines in generation.

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38 At the national level, the demand for electricity does not change between the baseline and the analyzed regulatory options (generation within the regions is allowed to vary) because meeting demand is an exogenous constraint imposed by the model.

At the national level, the magnitude in the net increase in total costs under Option 4, $103 million (0.2 percent), is similar to the magnitude under Option 2 and follows changes in generation. Total costs in the SERC regions increase of the most with $173 million (0.9 percent) and RFC costs show the decrease with $87 million (0.6 percent). Variable production costs at the national level are estimated to increase by $0.05 per MWh (0.2 percent), which is slightly higher than under Option 2. The highest increase is in SERC, with an increase of $0.11 per MWh (0.4 percent), whereas the other NERC regions experience increases between zero and 0.1 percent.

5.2.2.3 Impact on Individual Steam Electric Power Plants

Results *for the group* of steam electric power plants as a whole may mask shifts in economic performance among *individual* steam electric power plants. To assess potential plant-level effects, the EPA analyzed the distribution of plant-specific changes between the baseline and the regulatory options for three metrics: capacity utilization,[39] electricity generation, and variable production costs per MWh.[40]

Table 5-6 presents the estimated number of steam electric power plants with specific degrees of change in operations and financial performance as a result of the regulatory options. Metrics of greatest interest for assessing the adverse impacts of the regulatory options on steam electric power plants include the number of plants with reductions in capacity utilization or generation (on the left side of the table), and the number of plants with increases in variable production costs (on the right side of the table).

This table excludes steam electric power plants with estimated significant status changes in 2030 that render these metrics of change not meaningful – *i.e.*, a plant is assessed as either a full, partial, or avoided closure in either the baseline or the regulatory option. The measures presented in Table 5-5, such as *change in electricity generation*, are not meaningful for these plants. For example, for a plant that is projected to close in the baseline but avoids closure under the regulatory option, the percent change in electricity generation relative to baseline cannot be calculated. On this basis, 281 and 280 plants are excluded from assessment of effects on individual steam electric power plants under Options 2 and 4, respectively. In addition, the change in variable production cost per MWh of generation could not be developed for 38 plants with zero generation in either the baseline or under Options 2 and 4 (because the divisor, MWh, is zero). For *change in variable production cost per MWh*, these plants are recorded in the "N/A" column.

39 Capacity utilization is defined as generation divided by capacity times 8,760 hours.

40 Variable production costs per MWh is defined as variable O&M cost plus fuel cost divided by net generation projected in IPM.

Table 5-6: Impact of Regulatory Options on Individual In-Scope Plants at the Year 2030

Economic Measures	Reduction			No Change	Increase			N/A[b,c]
	> 3%	≥1% and <3%	<1%		<1%	≥1% and <3%	≥3%	
Option 2								
Change in Capacity Utilization[a]	4	5	44	277	63	9	3	281
Change in Generation	17	9	27	277	43	14	18	281
Change in Variable Production Costs/MWh	2	7	94	197	64	2	1	319
Option 4								
Change in Capacity Utilization[a]	5	8	50	278	54	8	3	280
Change in Generation	23	10	30	278	35	14	16	280
Change in Variable Production Costs/MWh	0	5	75	208	70	9	1	318

a. The change in capacity utilization is the difference between the capacity utilization percentages in the baseline and policy cases. For all other measures, the change is expressed as the percentage change between the baseline and policy values.

b. Plants with operating status changes in either baseline or policy scenario have been excluded from general table calculations. Thus, for Option 2, "N/A" reports 224 full and 52 partial baseline closures; 1 additional full closure as a result of the regulatory option; and 1 avoided full and 3 avoided partial closures as a result of the regulatory option. For Option 4, "N/A" reports 224 full and 52 partial baseline closures, and 1 avoided full and 3 avoided partial closures resulting from the option.

c. The change in variable production cost per MWh could not be developed for 38 plants with zero generation in either the baseline case or Options 2 or 4 policy cases.

Source: U.S. EPA Analysis, 2019

5.2.2.3.1 Findings for Regulatory Option 2 in Model Year 2030

For Option 2, the analysis of changes in individual plants indicates that most plants experience only slight effects – *i.e.*, no change or less than a one percent reduction or one percent increase. Only 9 plants (2 percent) are estimated to incur a reduction in capacity utilization of at least one percent and 26 plants (6 percent) incur a reduction in generation of at least one percent. Finally, only 3 plants (0.8 percent) are estimated incur an increase in variable production costs of at least one percent.

5.2.2.3.2 Findings for Regulatory Option 4 in Model Year 2030

Under Option 4, the analysis indicates that most plants experience only slight effects, though these effects are greater than for Option 2. Option 4 shows small reductions in capacity utilization and generation; only 13 plants (3 percent) incur more than a one percent reduction in capacity utilization and 33 plants (8 percent) experience a reduction in generation of at least one percent. Impacts on variable costs are larger than for Option 2, but also modest. The increase in variable production costs is estimated to exceed one percent for 10 plants (3 percent), 9 of which have an increase of at least one percent but less than three percent. The vast majority of steam electric power plants have variable production costs that either don't change or change by less than one percent.

5.3 Estimated Effects of the Regulatory Options on New Capacity

IPM results show no new coal-fired capacity projected during the analysis period. This continues to be the case for Option 2 and Option 4.

5.4 Uncertainties and Limitations

Despite the EPA's use of the best available information and data, the EPA's analyses of the electric power market and the overall economic impacts of the regulatory options involve several sources of uncertainty:

- *Steam electric power plant response to changes in production costs*: IPM includes information about announced retirements only to the extent that there is a high degree of certainty about the future implementation of the announced action (U.S. EPA, 2018a). To the extent that some utilities' business strategy and integrated resource plans call for the retirement of coal generation assets and transition toward other sources of energy such as renewables or natural gas that is separate from the factors modeled in IPM, then IPM may overstate avoided retirements resulting from cost savings under the regulatory options.

- *Demand for electricity*: IPM assumes that electricity demand at the national level will not change between the baseline and the analyzed options (generation within the regions is allowed to vary); this constraint is exogenous to the model. IPM V6 embeds a baseline energy demand forecast that is derived from the Department of Energy's *Annual Energy Outlook 2018* (AEO2018). IPM does not capture changes in demand that may result from electricity price changes associated with the regulatory options (*i.e.*, demand is inelastic with respect to price). While this constraint may underestimate total demand in policy options that have lower compliance costs relative to the baseline, the EPA takes the position that relaxing the constraint would not affect the results analyzed. As described in Section 5.2.1 and Section 5.2.2, the price changes associated with the analyzed regulatory options in most NERC regions are less than $0.30 per MWh (0.5 percent). The EPA therefore concludes that the assumption of inelastic demand-responses over these changes in prices is reasonable.

- *Fuel prices*: Prices of fuels (*e.g.*, natural gas and coal) are determined endogenously within IPM. IPM modeling of fuel prices uses both short- and long-term price signals to balance supply of, and demand in, competitive markets for the fuel across the modeled time horizon. The model relies on AEO2018's electric demand forecast for the US and employs a set of EPA assumptions regarding fuel supplies and the performance and cost of electric generation technologies as well as pollution controls. Differences in actual fuel prices relative to those modeled by IPM, such as lower natural gas prices that may result from increased domestic production, would be estimated to affect the cost of electricity generation and therefore the amount of electricity generated by steam electric power plants, irrespective of the regulatory options. More generally, differences in fuel prices, and related changes in electricity production costs, can affect the modeled dispatch profiles, planning for new/repowered capacity, and contribute to differences in a number of policy-relevant parameters such as electricity production costs, prices, and emission changes.

- *International imports*: IPM assumes that imports from Canada and Mexico do not change between the baseline and the options. Holding international imports fixed potentially understates the impacts of changes in production costs and electricity prices in U.S. domestic markets. The EPA does not expect that this assumption materially affects results, however, since IPM projects that only one of the eight NERC regions will import electricity (WECC) in 2030, and the level of imports compared to domestic generation in this region is very small (about 0.8 percent).

6 Assessment of the Impact of the Regulatory Options on Employment

6.1 Background and Context

In addition to addressing the costs and impacts of the regulatory options, the EPA discusses the potential impacts of this rulemaking on employment in this section. Such an analysis is of interest given the broad policy objective stated in Executive Order 13563: "Our regulatory system must protect public health, welfare, safety, and our environment while promoting economic growth, innovation, competitiveness, and job creation." A discussion of compliance costs is included in *Chapter 3* of this RIA.

In this Chapter, the EPA first provides an overview of the various ways that environmental regulation can affect employment. The EPA then qualitatively describes potential employment impacts for coal-fired steam electric power plants and pollution control suppliers. In addition, the EPA discusses labor effects for coal mining and other energy sources.

6.1.1 Employment Impacts of Environmental Regulations

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.

If the U.S. economy is at full employment, even a large-scale environmental regulation is unlikely to have a noticeable impact on aggregate net employment. 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 in the short term. Although the net change in the national workforce is estimated to be small under conditions of full employment, localized reductions in employment may adversely impact individuals and communities just as localized increases may have positive impacts.

An environmental regulation affecting the steam electric industry is estimated to have a variety of employment impacts. Transitional impacts include reduced employment at retiring coal-fired plants, 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). Other employment impacts include effects on labor supply and productivity resulting from changes in pollution, as well as effects on labor demand in generation of energy from other sources, such as natural gas and renewable energy.

6.1.2 Current State of Knowledge Based on the Peer-Reviewed Literature

While there is an extensive empirical, peer-reviewed literature analyzing the effect of environmental regulations on various economic outcomes including productivity, investment, competitiveness as well as environmental performance, there are no known studies on environmental deregulation's effects on employment, and only a few papers that examine the impact of more stringent environmental regulation on employment. However, this area of the literature has been growing. Berman and Bui (2001) suggest that new or more stringent environmental regulations do not have a substantial impact on net employment (either negative or positive) in the regulated sector. Similarly, Ferris, Shadbegian, and Wolverton (2014) also find that regulation-induced net employment impacts are close to zero in the regulated sector. Furthermore, Gray et al. (2014) find that pulp mills that had to comply with both the air and water regulations in EPA's 1998 "Cluster Rule" experienced relatively small and not always statistically significant, decreases in employment. Nevertheless, other empirical research suggests that regulation can have negative impacts on jobs. Sheriff et al. (2019) find negative impacts on employment at electric utilities from ozone regulations, but without changes in electricity generation, suggesting a labor-saving technical change. Results from Greenstone (2002) and Walker (2011, 2013) also suggest that more highly regulated counties may generate fewer jobs than less regulated ones. However, the methodology used in these two studies cannot estimate whether aggregate employment is lower or higher due to more stringent environmental regulation, it can only imply that relative employment growth in some sectors differs between more and less regulated areas. List et al. (2003) find some evidence that this type of geographic relocation, from more regulated areas to less regulated areas may be occurring. Overall, the peer-reviewed literature does not contain evidence that environmental regulation has a large impact on net employment (either negative or positive) in the long run across the whole economy.

6.1.3 Labor Supply and Macroeconomic Net Employment Effects

As described above, the small empirical literature on employment effects of environmental regulations focuses primarily on labor demand impacts. However, there is nascent literature focusing on regulation-induced effects on labor supply, though this literature remains very limited due to empirical challenges. This new research uses innovative methods and new data, and indicates that there may be observable impacts of environmental regulation on labor supply, even at pollution levels below mandated regulatory thresholds. Many researchers have found that lost workdays and sick days as well as mortality are reduced when pollution is reduced, although the studies focus specifically on air quality. Another literature estimates how worker productivity declines at the work site when pollution increases. Graff Zivin and Neidell (2013) review the work in this literature, focusing on how health and human capital may be affected by environmental quality, particularly air pollution. In previous research, Graff Zivin and Neidell (2012) use detailed worker-level productivity data paired with local ozone air quality monitoring data for one large California farm. They find "that ozone levels well below federal air quality standards have a significant impact on productivity," with results showing that a 10 parts per billion (ppb) increase in ozone concentrations decreases worker productivity by 5.5 percent. (Graff Zivin and Neidell, 2012, p. 3654). More recently, Chang et al. (2016) find that $PM_{2.5}$ levels have significant effects on the productivity of indoor workers. Their study examines workers at a pear packing factory in California and find that a 10-unit change in $PM_{2.5}$ leads to a decrease in worker productivity by about 6 percent. As most of the economic output in the U.S. is produced indoors, the implications of this study are of potentially greater magnitude than the earlier study on outdoor agricultural workers. Such studies are a compelling start to exploring this new area of research, considering the benefits of improved environmental quality on productivity, alongside the existing literature exploring the labor demand effects of environmental regulations.

The preceding has outlined the challenges associated with estimating net employment effects within the regulated sector, in the environmental protection sector, and labor supply impacts. These challenges make it difficult to accurately produce net employment estimates for the whole economy that would appropriately capture the way in which costs, compliance spending, and environmental benefits propagate through the macro-economy.

6.1.4 Distributional Considerations

In addition to macroeconomic considerations, 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. Communitywide 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).

6.2 Analysis Overview

6.2.1 Estimated Employment Effects in Coal-Fired Electric Power Plants Affected by the Regulatory Options

The regulatory options would have two broad categories of effect on the coal-fired power plants:

1. Coal-fired plants that are affected by the rule are estimated to install and operate compliance technology that is less costly than the ELGs technology bases in the 2015 rule. To the extent that some of these costs are driven by labor inputs, the savings may lead to decreased employment in these plants compared to the baseline.

2. Coal-fired plants may generate more electricity than would otherwise occur in the absence of the rule due to decreased production costs. In addition, some plants may avoid retirement that would

otherwise occur. These effects may lead to increased employment at coal fired power plants compared to the baseline.

The EPA estimates that changes in employment may occur due to incorporation of different pollution controls. As summarized in *Chapter 3*, the EPA estimated that annualized capital costs would be lower under all four regulatory options compared to the baseline. Approximately 50-59 percent of the annualized compliance costs for the regulatory options are annualized capital costs. These capital cost savings are not estimated to significantly affect employment at steam electric power plants themselves, but could decrease employment in industries that manufacture and install pollution control equipment.

The remaining cost savings consist of wastewater treatment O&M costs, including labor costs for the maintenance, repair, and operations of treatment equipment. Options 1, 2, and 3 yield O&M cost savings ranging from $19.0 million per year (Option 3) to $42.5 million per year (Option 2), on an after-tax basis. Option 4 actually increases annualized O&M costs by $34 million. Some of these changes in O&M costs savings could potentially affect employment in the steam electric power generating industry, but the changes are small relative to overall electricity production costs.[41]

IPM projects that total coal-fired generating capacity is estimated to increase between 2021 and 2050 by approximately 0.4-0.7 percent under Option 2 and 0.2-0.6 percent under Option 4.[42] In addition, IPM projects that in 2030, Option 2, would lead to avoided retirement of 1.1 GW (2.2 percent) of coal-fired capacity, and Option 4 would lead to avoided retirement of 0.7 GW (1.4 percent). The direction of estimated changes in coal-fired generation capacity projected by IPM indicates potential increase in total O&M labor at coal-fired electricity plants, compared to the baseline. However, given the relatively small effect of the regulatory options on total capacity and avoided generating unit retirements described above, the EPA estimates any increase in labor in the steam electric generating industry to be small.

6.2.2 Coal Mining and Other Energy Sources

This analysis uses the results from IPM to discuss potential labor effects in the coal mining, natural gas extraction, and non-hydro renewable generation. The IPM analysis of regulatory options provides estimates of the changes in coal usage (in million short tons per year, or MT), natural gas usage (in trillion cubic feet), and non-hydro renewable generation (in thousand GWh) in 2021-2050. IPM provides changes in coal demand (in short tons) in three coal supply regions: Appalachia (Pennsylvania through Mississippi), Interior (Indiana through Texas), and the West (North Dakota through Arizona).

IPM projects that coal use would increase by 0.1-0.4 percent under Option 2 from 2021-2050 relative to the baseline. This could lead to a small overall increase in coal mining employment. However, changes in coal use vary by region, with the West estimated to experience consistent increases over the period of analysis (0.2 percent to 0.6 percent), while Appalachia and the Interior are estimated to experience changes in coal use ranging from -0.5 percent to 1.7 percent and -0.3 percent to 0.4 percent, respectively, during that period. Natural gas usage and non-hydro renewable generation is estimated to slightly

[41] As summarized in Table 5-5, IPM projections for the model year 2030 show net reductions of 0.3 percent in fixed O&M costs by steam electric power plants for Option 2 as compared to the baseline, and negligible changes (less than 0.1 percent) for Option 4.

[42] See Chapter 5 for a description of the IPM analysis and results.

decrease overall under Option 2 relative to the baseline, which may lead to declines in employment in the extraction and generation of energy from these other sources.

Under Option 4, IPM projects that the direction of coal use changes would vary, with changes ranging between -0.2 percent and 0.2 percent. Effects vary by region, with fluctuations between negative and positive in Appalachia, the Interior, and the West. As a result, it is unclear what the employment impact on coal mining would be under Option 4. Since natural gas usage and non-hydro renewable generation similarly fluctuate, it is also unclear what to expect regarding employment impacts in these other sectors.

6.3 Findings

In conclusion, analyzing how environmental regulations will impact net employment is a difficult task, requiring consideration of labor demand in both the regulated and environmental protection sectors. Economic theory predicts that the total effect of an environmental regulation on labor demand in regulated sectors is not necessarily positive or negative. Peer-reviewed econometric studies that use a structural approach, applicable to overall net effects in the regulated sectors, converge on the finding that such effects, whether positive or negative, have been small and have not affected employment in the national economy in a significant way. Overall, effects of the regulatory options on O&M labor demand at coal-fired steam electric power plants seem likely to be positive given the net increase in capacity and generation in the steam electric power sector.

7 Assessment of Potential Electricity Price Effects

7.1 Analysis Overview

The EPA assessed the potential impacts of the regulatory options on electricity prices. Following the methodology the EPA used to analyze the 2015 rule (U.S. EPA, 2015b), the Agency conducted this analysis for the baseline and each of the four regulatory options in two parts:

- An assessment of the potential annual increase in electricity costs per MWh of total electricity sales (Section 7.2)
- An assessment of the potential annual increase in household electricity costs (Section 7.3).

As is the case with the plant-level and parent entity-level cost-to-revenue screening analyses discussed in Chapter 4 (Economic Impact Screening Analyses), this analysis of electricity price effects uses a historical snapshot of electricity generation against which to assess the relative impacts of the regulatory options. However, unlike the plant- and entity-level screening analyses which assume that steam electric power plants and their parent entities would absorb 100 percent of the compliance burden (zero cost pass-through), this electricity price impact assessment assumes the opposite: 100 percent pass-through of compliance costs through electricity prices (*i.e.*, full cost pass-through).

Although this convenient analytical simplification does not reflect actual market conditions,[43] the EPA judges this assumption appropriate for two reasons: (1) the majority of steam electric power plants operate in the cost-of-service framework and *may be* able to recover increases in their production costs through increased electricity prices and (2) for plants operating in states where electric power generation has been deregulated, it would not be possible to estimate this consumer price effect at the state level. Thus, this 100 percent cost pass-through assumption represents a "worst-case" impact scenario from the perspective of the electricity consumers. To the extent that all compliance-related costs are *not* passed forward to consumers but are absorbed, at least in part, by electric power generators, this analysis overstates consumer impacts.

It is also important to note that, if the full cost pass-through condition assumed in this analysis were to occur, then the screening analyses assessed in *Chapter 4* would overstate the impacts to plants and owners of these plants because the two conditions (full cost pass-through and no cost pass-through) could not simultaneously occur for the same steam electric power plant.

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43 Plants located in states where electricity prices remain regulated under the traditional cost-of-service rate regulation framework may be able to recover compliance cost-based increases in their production costs through increased electricity rates, depending on the business operation model of the plant owner(s), the ownership and operating structure of the plant itself, and the role of market mechanisms used to sell electricity. In contrast, in states in which electric power generation has been deregulated, cost recovery is not guaranteed. While plants operating within deregulated electricity markets *may be* able to recover some of their additional production costs in increased revenue, it is not possible to determine the extent of cost recovery ability for each plant. Moreover, even though individual plants may not be able to recover all of their compliance costs through increased revenues, the market-level effect may still be that consumers would see higher overall electricity prices because of changes in the cost structure of electricity supply and resulting changes in market-clearing prices in deregulated generation markets.

7.2 Assessment of Impact of Compliance Costs on Electricity Prices

The EPA assessed the potential increase in electricity prices to the four electricity consumer groups: residential, commercial, industrial, and transportation.

7.2.1 Analysis Approach and Data Inputs

For this analysis, the EPA assumed that compliance costs would be fully passed through as increased electricity prices and allocated these costs among consumer groups (residential, commercial, industrial, and transportation) in proportion to the historical quantity of electricity consumed by each group. The EPA performed this analysis at the level of the North American Electric Reliability Corporation (NERC) region. Using the NERC region as the basis for this analysis is appropriate given the structure and functioning of sub-national electricity markets, around which NERC regions are defined. The analysis, which uses the exact same approach as used for the 2015 rule analysis (see Chapter 7 in the 2015 RIA document [U.S. EPA, 2015b]), involves the following steps:

- The EPA summed weighted pre-tax plant-level annualized compliance costs by NERC region.[44, 45]
- The EPA estimated the approximate average price impact per unit of electricity consumption by dividing total annualized compliance costs by the projected total MWh of sales in 2020 by NERC region, from AEO2018.
- The EPA compared the estimated average price effect to the projected electricity price by consumer group and NERC region for 2020 from AEO2018.

7.2.2 Key Findings for Regulatory Options

As reported in Table 7-1, changes are very small for all regulatory options; the maximum difference in price effect is a fraction of a cent per kWh. Under Options 1, 2, and 3, the regions with the greatest cost savings per unit of electricity are SERC and RFC, whereas under Option 4, SERC and MRO are the regions with the greatest cost savings. Overall across the United States, Option 2 results in the highest cost savings of 0.005¢ per kWh, and Option 4 results in the lowest cost savings of 0.001¢ per kWh.

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44 These compliance costs are in 2018 dollars as of a given technology implementation year (2021 through 2028) and discounted to 2020 at 7 percent. This analysis accounts for the different years in which plants are estimated to implement the compliance technologies in order to reflect the effect of differences in timing of these electricity price impacts in terms of cost to household ratepayers and society. Costs and ratepayer effects occurring farther in the future (*e.g.*, in the last year of the technology implementation period) have a lower present value of impact than those that occur sooner following rule promulgation. Estimating the cost and ratepayer effect as of the assumed technology implementation year (2021through 2028) and then discounting these effects to a single analysis year (2020) accounts for this consideration.

45 For this analysis, the EPA brought compliance costs forward to a given compliance year using the CCI and ECI.

Table 7-1: Compliance Cost per KWh Sales by NERC Region and Regulator Option in 2020 (2018$)

NERC[a]	Total Electricity Sales (at 2020; MWh)	National Pre-Tax Compliance Costs (at 2020; 2018$)	Costs per Unit of Sales (2018¢/kWh Sales)	Incremental Annualized Pre-Tax Compliance Costs (at 2020; 2018$)	Incremental Costs per Unit of Sales (2018¢/kWh Sales)
Baseline					
FRCC	222,490,204	$9,560,479	¢0.004	N/A	N/A
MRO	223,130,516	$18,527,879	¢0.008	N/A	N/A
NPCC	262,100,581	$7,180,479	¢0.003	N/A	N/A
RFC	833,731,788	$166,206,817	¢0.020	N/A	N/A
SERC	992,215,820	$204,589,668	¢0.021	N/A	N/A
SPP	205,244,514	$24,666,017	¢0.012	N/A	N/A
TRE	357,430,000	$6,680,661	¢0.002	N/A	N/A
WECC	694,787,895	$4,982,032	¢0.001	N/A	N/A
US[a]	**3,806,416,322**	**$442,394,030**	**¢0.012**	N/A	N/A
Option 1					
FRCC	222,490,204	$1,020,938	¢0.000	-$8,539,541	-¢0.004
MRO	223,130,516	$14,147,566	¢0.006	-$4,380,313	-¢0.002
NPCC	262,100,581	$5,371,158	¢0.002	-$1,809,321	-¢0.001
RFC	833,731,788	$106,415,315	¢0.013	-$59,791,502	-¢0.007
SERC	992,215,820	$122,399,799	¢0.012	-$82,189,869	-¢0.008
SPP	205,244,514	$18,614,853	¢0.009	-$6,051,164	-¢0.003
TRE	357,430,000	$4,252,972	¢0.001	-$2,427,689	-¢0.001
WECC	694,787,895	$4,555,803	¢0.001	-$426,229	¢0.000
US[a]	**3,806,416,322**	**$276,778,404**	**¢0.007**	**-$165,615,626**	**-¢0.004**
Option 2					
FRCC	222,490,204	$5,648,017	¢0.003	-$3,912,461	-¢0.002
MRO	223,130,516	$6,443,047	¢0.003	-$12,084,832	-¢0.005
NPCC	262,100,581	$357,706	¢0.000	-$6,822,773	-¢0.003
RFC	833,731,788	$112,152,958	¢0.013	-$54,053,859	-¢0.006
SERC	992,215,820	$117,774,447	¢0.012	-$86,815,222	-¢0.009
SPP	205,244,514	$18,378,460	¢0.009	-$6,287,557	-¢0.003
TRE	357,430,000	$3,508,153	¢0.001	-$3,172,508	-¢0.001
WECC	694,787,895	$2,491,442	¢0.000	-$2,490,590	¢0.000
US[a]	**3,806,416,322**	**$266,754,229**	**¢0.007**	**-$175,639,801**	**-¢0.005**
Option 3					
FRCC	222,490,204	$5,648,017	¢0.003	-$3,912,461	-¢0.002
MRO	223,130,516	$13,454,178	¢0.006	-$5,073,701	-¢0.002
NPCC	262,100,581	$5,925,643	¢0.002	-$1,254,836	¢0.000
RFC	833,731,788	$124,950,189	¢0.015	-$41,256,628	-¢0.005
SERC	992,215,820	$138,504,202	¢0.014	-$66,085,466	-¢0.007
SPP	205,244,514	$19,511,015	¢0.010	-$5,155,002	-¢0.003
TRE	357,430,000	$3,508,153	¢0.001	-$3,172,508	-¢0.001
WECC	694,787,895	$4,555,803	¢0.001	-$426,229	¢0.000
US[a]	**3,806,416,322**	**$316,057,199**	**¢0.008**	**-$126,336,831**	**-¢0.003**
Option 4					
FRCC	222,490,204	$14,931,818	¢0.007	$5,371,340	¢0.002
MRO	223,130,516	$13,655,562	¢0.006	-$4,872,316	-¢0.002
NPCC	262,100,581	$6,162,717	¢0.002	-$1,017,762	¢0.000
RFC	833,731,788	$162,382,386	¢0.019	-$3,824,430	¢0.000

Table 7-1: Compliance Cost per KWh Sales by NERC Region and Regulator Option in 2020 (2018$)

NERC[a]	Total Electricity Sales (at 2020; MWh)	National Pre-Tax Compliance Costs (at 2020; 2018$)	Costs per Unit of Sales (2018¢/kWh Sales)	Incremental Annualized Pre-Tax Compliance Costs (at 2020; 2018$)	Incremental Costs per Unit of Sales (2018¢/kWh Sales)
SERC	992,215,820	$189,131,490	¢0.018	-$15,458,178	-¢0.002
SPP	205,244,514	$22,303,439	¢0.011	-$2,362,578	-¢0.001
TRE	357,430,000	$3,760,141	¢0.001	-$2,920,520	-¢0.001
WECC	694,787,895	$4,555,803	¢0.001	-$426,229	¢0.000
US[a]	**3,806,416,322**	**$416,883,357**	**¢0.011**	**-$25,510,674**	**-¢0.001**

a. ELG compliance costs are zero in the AK and HICC regions and these regions are therefore omitted from the presentation. Because of this, the sum of electricity sales for all regions do not sum to the total for the United States. Total electricity sales are 6,000,581 MWh and 9,284,423 MWh in AK and HICC, respectively.

Source: U.S. EPA Analysis, 2019

To determine the relative significance of compliance costs on electricity prices across consumer groups, the EPA compared the per kWh compliance cost to retail electricity prices projected by EIA (AEO2018; EIA, 2018a) by consuming group and for the average of the groups. As reported in Table 7-2, across the United States, the baseline is estimated to result in an average electricity price increase for all sectors of 0.012 cents per kWh (0.11 percent of the average price of 10.8 cents per kWh). Table 7-3 presents incremental impacts on electricity prices under the four regulatory options relative to the baseline. Across all options, average electricity price increases are less than under the baseline, with cost savings ranging from 0.001 cents per kWh (0.1 percent) under Option 4, to 0.005 cents per kWh (0.4 percent) under Option 2.

Looking across the four consumer groups and assuming that any price change would apply equally to all consumer groups, under all scenarios industrial consumers are estimated to experience the highest price changes relative to the electricity price basis, while residential consumers are estimated to experience the lowest price changes, shown in Table 7-2. As with the average national results for all sectors, industrial and residential price increases under all four options are less than under the baseline, yielding estimated cost savings to these consumer groups when compared to the 2015 rule. As presented in Table 7-3, industrial consumers and residential consumers are estimated to experience cost savings of 0.06 percent and 0.04 percent, respectively under Option 2. Under Option 4, industrial and residential consumers are estimated to experience cost savings of 0.01 percent under Option 4. The higher relative price effect to industrial consumers is due to their lower electricity rates and EPA's assumption of uniform changes across all consumer groups; it does not reflect differential distribution of the incremental costs across consumer groups.

Table 7-2: Projected 2020 Price (Cents per kWh of Sales) and Potential Price Increase Due to Compliance Costs by NERC Region and Regulatory Option (2018$)

		Residential		Commercial		Industrial		Transportation		All Sectors Average	
NERC[b]	Compliance Costs (2018¢ /kWh)	EIA Price Basis (2018¢ /kWh)	% Change[a]	EIA Price Basis (2018¢ /kWh)	% Change[a]	EIA Price Basis (2018¢ /kWh)	% Change[a]	EIA Price Basis (2018¢ /kWh)	% Change[a]	EIA Price Basis (2018¢ /kWh)	% Change[a]
Baseline											
FRCC	¢0.004	¢11.7	0.04%	¢9.6	0.04%	¢8.2	0.05%	¢10.8	0.04%	¢10.6	0.04%
MRO	¢0.008	¢12.1	0.07%	¢9.7	0.09%	¢7.2	0.12%	¢12.5	0.07%	¢9.5	0.09%
NPCC	¢0.003	¢19.1	0.01%	¢13.4	0.02%	¢13.5	0.02%	¢12.0	0.02%	¢15.5	0.02%
RFC	¢0.020	¢14.5	0.14%	¢10.8	0.18%	¢7.8	0.26%	¢10.0	0.20%	¢11.2	0.18%
SERC	¢0.021	¢12.2	0.17%	¢10.4	0.20%	¢6.5	0.32%	¢12.1	0.17%	¢10.0	0.21%
SPP	¢0.012	¢11.9	0.10%	¢10.0	0.12%	¢6.7	0.18%	¢12.3	0.10%	¢9.7	0.12%
TRE	¢0.002	¢9.6	0.02%	¢8.8	0.02%	¢5.8	0.03%	¢7.8	0.02%	¢8.3	0.02%
WECC	¢0.001	¢13.8	0.01%	¢12.2	0.01%	¢7.6	0.01%	¢13.0	0.01%	¢11.6	0.01%
US	**¢0.012**	**¢13.1**	**0.09%**	**¢10.9**	**0.11%**	**¢7.3**	**0.16%**	**¢11.4**	**0.10%**	**¢10.8**	**0.11%**
Option 1											
FRCC	¢0.000	¢11.7	0.00%	¢9.6	0.00%	¢8.2	0.01%	¢10.8	0.00%	¢10.6	0.00%
MRO	¢0.006	¢12.1	0.05%	¢9.7	0.07%	¢7.2	0.09%	¢12.5	0.05%	¢9.5	0.07%
NPCC	¢0.002	¢19.1	0.01%	¢13.4	0.02%	¢13.5	0.02%	¢12.0	0.02%	¢15.5	0.01%
RFC	¢0.013	¢14.5	0.09%	¢10.8	0.12%	¢7.8	0.16%	¢10.0	0.13%	¢11.2	0.11%
SERC	¢0.012	¢12.2	0.10%	¢10.4	0.12%	¢6.5	0.19%	¢12.1	0.10%	¢10.0	0.12%
SPP	¢0.009	¢11.9	0.08%	¢10.0	0.09%	¢6.7	0.14%	¢12.3	0.07%	¢9.7	0.09%
TRE	¢0.001	¢9.6	0.01%	¢8.8	0.01%	¢5.8	0.02%	¢7.8	0.02%	¢8.3	0.01%
WECC	¢0.001	¢13.8	0.00%	¢12.2	0.01%	¢7.6	0.01%	¢13.0	0.01%	¢11.6	0.01%
US	**¢0.007**	**¢13.1**	**0.06%**	**¢10.9**	**0.07%**	**¢7.3**	**0.10%**	**¢11.4**	**0.06%**	**¢10.8**	**0.07%**
Option 2											
FRCC	¢0.003	¢11.7	0.02%	¢9.6	0.03%	¢8.2	0.03%	¢10.8	0.02%	¢10.6	0.02%
MRO	¢0.003	¢12.1	0.02%	¢9.7	0.03%	¢7.2	0.04%	¢12.5	0.02%	¢9.5	0.03%
NPCC	¢0.000	¢19.1	0.00%	¢13.4	0.00%	¢13.5	0.00%	¢12.0	0.00%	¢15.5	0.00%
RFC	¢0.013	¢14.5	0.09%	¢10.8	0.12%	¢7.8	0.17%	¢10.0	0.13%	¢11.2	0.12%
SERC	¢0.012	¢12.2	0.10%	¢10.4	0.11%	¢6.5	0.18%	¢12.1	0.10%	¢10.0	0.12%
SPP	¢0.009	¢11.9	0.08%	¢10.0	0.09%	¢6.7	0.13%	¢12.3	0.07%	¢9.7	0.09%
TRE	¢0.001	¢9.6	0.01%	¢8.8	0.01%	¢5.8	0.02%	¢7.8	0.01%	¢8.3	0.01%
WECC	¢0.000	¢13.8	0.00%	¢12.2	0.00%	¢7.6	0.00%	¢13.0	0.00%	¢11.6	0.00%
US	**¢0.007**	**¢13.1**	**0.05%**	**¢10.9**	**0.06%**	**¢7.3**	**0.10%**	**¢11.4**	**0.06%**	**¢10.8**	**0.06%**
Option 3											
FRCC	¢0.003	¢11.7	0.02%	¢9.6	0.03%	¢8.2	0.03%	¢10.8	0.02%	¢10.6	0.02%
MRO	¢0.006	¢12.1	0.05%	¢9.7	0.06%	¢7.2	0.08%	¢12.5	0.05%	¢9.5	0.06%
NPCC	¢0.002	¢19.1	0.01%	¢13.4	0.02%	¢13.5	0.02%	¢12.0	0.02%	¢15.5	0.01%
RFC	¢0.015	¢14.5	0.10%	¢10.8	0.14%	¢7.8	0.19%	¢10.0	0.15%	¢11.2	0.13%
SERC	¢0.014	¢12.2	0.11%	¢10.4	0.13%	¢6.5	0.22%	¢12.1	0.12%	¢10.0	0.14%
SPP	¢0.010	¢11.9	0.08%	¢10.0	0.09%	¢6.7	0.14%	¢12.3	0.08%	¢9.7	0.10%
TRE	¢0.001	¢9.6	0.01%	¢8.8	0.01%	¢5.8	0.02%	¢7.8	0.01%	¢8.3	0.01%
WECC	¢0.001	¢13.8	0.00%	¢12.2	0.01%	¢7.6	0.01%	¢13.0	0.01%	¢11.6	0.01%
US	**¢0.008**	**¢13.1**	**0.06%**	**¢10.9**	**0.08%**	**¢7.3**	**0.11%**	**¢11.4**	**0.07%**	**¢10.8**	**0.08%**

Table 7-2: Projected 2020 Price (Cents per kWh of Sales) and Potential Price Increase Due to Compliance Costs by NERC Region and Regulatory Option (2018$)

NERC[b]	Compliance Costs (2018¢ /kWh)	Residential		Commercial		Industrial		Transportation		All Sectors Average	
		EIA Price Basis (2018¢ /kWh)	% Change [a]	EIA Price Basis (2018¢ /kWh)	% Change [a]	EIA Price Basis (2018¢ /kWh)	% Change [a]	EIA Price Basis (2018¢ /kWh)	% Change [a]	EIA Price Basis (2018¢ /kWh)	% Change [a]
Option 4											
FRCC	¢0.007	¢11.7	0.06%	¢9.6	0.07%	¢8.2	0.08%	¢10.8	0.06%	¢10.6	0.06%
MRO	¢0.006	¢12.1	0.05%	¢9.7	0.06%	¢7.2	0.09%	¢12.5	0.05%	¢9.5	0.06%
NPCC	¢0.002	¢19.1	0.01%	¢13.4	0.02%	¢13.5	0.02%	¢12.0	0.02%	¢15.5	0.02%
RFC	¢0.019	¢14.5	0.13%	¢10.8	0.18%	¢7.8	0.25%	¢10.0	0.19%	¢11.2	0.17%
SERC	¢0.019	¢12.2	0.16%	¢10.4	0.18%	¢6.5	0.30%	¢12.1	0.16%	¢10.0	0.19%
SPP	¢0.011	¢11.9	0.09%	¢10.0	0.11%	¢6.7	0.16%	¢12.3	0.09%	¢9.7	0.11%
TRE	¢0.001	¢9.6	0.01%	¢8.8	0.01%	¢5.8	0.02%	¢7.8	0.01%	¢8.3	0.01%
WECC	¢0.001	¢13.8	0.00%	¢12.2	0.01%	¢7.6	0.01%	¢13.0	0.01%	¢11.6	0.01%
US	**¢0.011**	**¢13.1**	**0.08%**	**¢10.9**	**0.10%**	**¢7.3**	**0.15%**	**¢11.4**	**0.10%**	**¢10.8**	**0.10%**

a. The rate impact analysis assumes full pass-through of all compliance costs to electricity consumers.

b. ELG compliance costs are zero in the AK and HICC regions and these regions are therefore omitted from the presentation.

Sources: U.S. EPA Analysis, 2019; EIA, 2017b; EIA, 2018a

Table 7-3: Potential Incremental Price Changes Relative to Baseline Due to Compliance Costs by NERC Region and Regulatory Option (2018$)

NERC[b]	Δ Compliance Costs (2018¢/ kWh)	Δ Residential Price [a]	Δ Commercial Price [a]	Δ Industrial Price [a]	Δ Transportation Price [a]	Δ All Sectors Average Price [a]
Option 1						
FRCC	-¢0.004	-0.03%	-0.04%	-0.05%	-0.04%	-0.04%
MRO	-¢0.002	-0.02%	-0.02%	-0.03%	-0.02%	-0.02%
NPCC	-¢0.001	0.00%	-0.01%	-0.01%	-0.01%	0.00%
RFC	-¢0.007	-0.05%	-0.07%	-0.09%	-0.07%	-0.06%
SERC	-¢0.008	-0.07%	-0.08%	-0.13%	-0.07%	-0.08%
SPP	-¢0.003	-0.02%	-0.03%	-0.04%	-0.02%	-0.03%
TRE	-¢0.001	-0.01%	-0.01%	-0.01%	-0.01%	-0.01%
WECC	¢0.000	0.00%	0.00%	0.00%	0.00%	0.00%
US	**-¢0.004**	**-0.03%**	**-0.04%**	**-0.06%**	**-0.04%**	**-0.04%**
Option 2						
FRCC	-¢0.002	-0.02%	-0.02%	-0.02%	-0.02%	-0.02%
MRO	-¢0.005	-0.04%	-0.06%	-0.08%	-0.04%	-0.06%
NPCC	-¢0.003	-0.01%	-0.02%	-0.02%	-0.02%	-0.02%
RFC	-¢0.006	-0.04%	-0.06%	-0.08%	-0.06%	-0.06%
SERC	-¢0.009	-0.07%	-0.08%	-0.14%	-0.07%	-0.09%
SPP	-¢0.003	-0.03%	-0.03%	-0.05%	-0.02%	-0.03%
TRE	-¢0.001	-0.01%	-0.01%	-0.02%	-0.01%	-0.01%
WECC	¢0.000	0.00%	0.00%	0.00%	0.00%	0.00%
US	**-¢0.005**	**-0.04%**	**-0.04%**	**-0.06%**	**-0.04%**	**-0.04%**

Table 7-3: Potential Incremental Price Changes Relative to Baseline Due to Compliance Costs by NERC Region and Regulatory Option (2018$)

NERC[b]	Δ Compliance Costs (2018¢/ kWh)	Δ Residential Price [a]	Δ Commercial Price [a]	Δ Industrial Price [a]	Δ Transportation Price [a]	Δ All Sectors Average Price [a]
Option 3						
FRCC	-¢0.002	-0.02%	-0.02%	-0.02%	-0.02%	-0.02%
MRO	-¢0.002	-0.02%	-0.02%	-0.03%	-0.02%	-0.02%
NPCC	¢0.000	0.00%	0.00%	0.00%	0.00%	0.00%
RFC	-¢0.005	-0.03%	-0.05%	-0.06%	-0.05%	-0.04%
SERC	-¢0.007	-0.05%	-0.06%	-0.10%	-0.06%	-0.07%
SPP	-¢0.003	-0.02%	-0.03%	-0.04%	-0.02%	-0.03%
TRE	-¢0.001	-0.01%	-0.01%	-0.02%	-0.01%	-0.01%
WECC	¢0.000	0.00%	0.00%	0.00%	0.00%	0.00%
US	**-¢0.003**	**-0.03%**	**-0.03%**	**-0.05%**	**-0.03%**	**-0.03%**
Option 4						
FRCC	¢0.002	0.02%	0.03%	0.03%	0.02%	0.02%
MRO	-¢0.002	-0.02%	-0.02%	-0.03%	-0.02%	-0.02%
NPCC	¢0.000	0.00%	0.00%	0.00%	0.00%	0.00%
RFC	¢0.000	0.00%	0.00%	-0.01%	0.00%	0.00%
SERC	-¢0.002	-0.01%	-0.01%	-0.02%	-0.01%	-0.02%
SPP	-¢0.001	-0.01%	-0.01%	-0.02%	-0.01%	-0.01%
TRE	-¢0.001	-0.01%	-0.01%	-0.01%	-0.01%	-0.01%
WECC	¢0.000	0.00%	0.00%	0.00%	0.00%	0.00%
US	**-¢0.001**	**-0.01%**	**-0.01%**	**-0.01%**	**-0.01%**	**-0.01%**

a. The rate impact analysis assumes full pass-through of all compliance costs to electricity consumers.
b. ELG compliance costs are zero in the AK and HICC regions and these regions are therefore omitted from the presentation.

Sources: U.S. EPA Analysis, 2019; EIA, 2017b; EIA, 2018a

7.2.3 Uncertainties and Limitations

As noted above, the assumption of 100 percent pass-through of compliance costs to electricity prices represents a worst-case scenario from the perspective of consumers. To the extent that some steam electric power plants are not able to pass their compliance costs to consumers through higher electricity rates, this analysis overstates the potential impact of the baseline and regulatory options on electricity consumers.

In addition, this analysis assumes that costs would be passed on in the form of a flat-rate price increase per unit of electricity, to be applied equally to all consumer groups. This assumption is appropriate to assess the general magnitude of potential price increases. The allocation of costs to different consumer groups could be higher or lower than estimated by this approach.

7.3 Assessment of Impact of Compliance Costs on Household Electricity Costs

The EPA also assessed the potential increases in the cost of electricity to residential households.

7.3.1 Analysis Approach and Data Inputs

For this analysis, the EPA again assumed that compliance costs would be fully passed through as increased electricity prices and allocated these costs to residential households in proportion to the baseline electricity consumption. The EPA analyzed the potential impact on annual electricity costs at the level of the 'average' household, using the estimated household electricity consumption quantity by NERC region. Following the approach used in analyzing the 2015 rule (U.S. EPA, 2015b), the steps in this calculation are as follows:

- As done for the electricity price analysis discussed in Section 7.2, to estimate total annual cost in each NERC region, the EPA summed weighted pre-tax, plant-level annualized compliance costs by NERC region.[46]
- As was done for the analysis of impact of compliance costs on electricity prices, the EPA divided total compliance costs by the total MWh of sales reported for each NERC region. The EPA used electricity sales (in MWh) for 2020 from AEO2018.[47]
- To calculate average annual electricity sales per household, the EPA divided the total quantity of *residential* sales (in MWh) for 2016 in each NERC region by the number of households in that region; the Agency obtained both the quantity of residential sales and the number of households from the 2016 EIA-861 database (EIA, 2017b). For this analysis, the EPA assumed that the average quantity of electricity sales per household by NERC region would remain the same in 2020 as in 2016.
- To assess the potential annual cost impact per household, the EPA multiplied the estimated average price impact by the average quantity of electricity sales per household in 2016 by NERC region.

7.3.2 Key Findings for Regulatory Options

Table 7-4 reports the results of this analysis by NERC region for each option, and overall for the United States.[48]

The average incremental annual cost savings per residential household is greatest in SERC and the least in WECC under all options. On the national level, cost savings are greatest on average under Option 2, with average cost savings per residential household of $0.49 per year; by region, cost savings range between $0.03-$1.20 per year. The least cost savings occur under Option 4, with average cost savings per residential household of $0.07 per year; by region, cost savings range between $0.01-$0.21 per year, with one region (FRCC) projected to see an increase in average cost per household of $0.33.

[46] Compliance costs in the ASCC and HICC regions are zero and EPA therefore did not include these regions in its analysis.

[47] AEO does not provide information for HICC and ASSC. None of the plants estimated to incur compliance costs as a result of the proposed ELG, however, are located in these two NERC regions.

[48] Average annual cost per residential household is zero in ASCC and HICC for the baseline and the four options and these regions are therefore omitted from the details. They are included in the U.S. totals.

Table 7-4: Average Incremental Annual Cost per Household in 2020 by NERC Region and Regulatory Option (2018$)

	Constant values				Incremental values [a]		
NERC[b]	Total Electricity Sales (MWh)	Residential Electricity Sales (MWh)	Number of Households	Residential Sales per Residential Household (MWh)	Total Incremental Pre-Tax Compliance Costs (at 2020; 2018$)	Incremental Compliance Costs per Unit of Sales (2018$ /MWh)	Incremental Compliance Costs per Residential Household (2018$)
Option 1							
FRCC	222,490,204	123,474,310	9,157,068	13.48	-$8,539,541	-$0.04	-$0.52
MRO	223,130,516	61,667,737	6,157,998	10.01	-$4,380,313	-$0.02	-$0.20
NPCC	262,100,581	148,760,464	18,761,676	7.93	-$1,809,321	-$0.01	-$0.05
RFC	833,731,788	352,481,555	35,967,640	9.80	-$59,791,502	-$0.07	-$0.70
SERC	992,215,820	403,431,581	29,294,201	13.77	-$82,189,869	-$0.08	-$1.14
SPP	205,244,514	28,987,604	2,451,321	11.83	-$6,051,164	-$0.03	-$0.35
TRE	357,430,000	113,645,980	8,236,191	13.80	-$2,427,689	-$0.01	-$0.09
WECC	694,787,895	255,116,789	29,814,787	8.56	-$426,229	$0.00	-$0.01
US[b]	**3,806,416,322**	**1,492,029,155**	**140,547,123**	**10.62**	**-$165,615,626**	**-$0.04**	**-$0.46**
Option 2							
FRCC	222,490,204	123,474,310	9,157,068	13.48	-$3,912,461	-$0.02	-$0.24
MRO	223,130,516	61,667,737	6,157,998	10.01	-$12,084,832	-$0.05	-$0.54
NPCC	262,100,581	148,760,464	18,761,676	7.93	-$6,822,773	-$0.03	-$0.21
RFC	833,731,788	352,481,555	35,967,640	9.80	-$54,053,859	-$0.06	-$0.64
SERC	992,215,820	403,431,581	29,294,201	13.77	-$86,815,222	-$0.09	-$1.20
SPP	205,244,514	28,987,604	2,451,321	11.83	-$6,287,557	-$0.03	-$0.36
TRE	357,430,000	113,645,980	8,236,191	13.80	-$3,172,508	-$0.01	-$0.12
WECC	694,787,895	255,116,789	29,814,787	8.56	-$2,490,590	$0.00	-$0.03
US[b]	**3,806,416,322**	**1,492,029,155**	**140,547,123**	**10.62**	**-$175,639,801**	**-$0.05**	**-$0.49**
Option 3							
FRCC	222,490,204	123,474,310	9,157,068	13.48	-$3,912,461	-$0.02	-$0.24
MRO	223,130,516	61,667,737	6,157,998	10.01	-$5,073,701	-$0.02	-$0.23
NPCC	262,100,581	148,760,464	18,761,676	7.93	-$1,254,836	$0.00	-$0.04
RFC	833,731,788	352,481,555	35,967,640	9.80	-$41,256,628	-$0.05	-$0.48
SERC	992,215,820	403,431,581	29,294,201	13.77	-$66,085,466	-$0.07	-$0.92
SPP	205,244,514	28,987,604	2,451,321	11.83	-$5,155,002	-$0.03	-$0.30
TRE	357,430,000	113,645,980	8,236,191	13.80	-$3,172,508	-$0.01	-$0.12
WECC	694,787,895	255,116,789	29,814,787	8.56	-$426,229	$0.00	-$0.01
US[b]	**3,806,416,322**	**1,492,029,155**	**140,547,123**	**10.62**	**-$126,336,831**	**-$0.03**	**-$0.35**
Option 4							
FRCC	222,490,204	123,474,310	9,157,068	13.48	$5,371,340	$0.02	$0.33
MRO	223,130,516	61,667,737	6,157,998	10.01	-$4,872,316	-$0.02	-$0.22
NPCC	262,100,581	148,760,464	18,761,676	7.93	-$1,017,762	$0.00	-$0.03
RFC	833,731,788	352,481,555	35,967,640	9.80	-$3,824,430	$0.00	-$0.04
SERC	992,215,820	403,431,581	29,294,201	13.77	-$15,458,178	-$0.02	-$0.21
SPP	205,244,514	28,987,604	2,451,321	11.83	-$2,362,578	-$0.01	-$0.14
TRE	357,430,000	113,645,980	8,236,191	13.80	-$2,920,520	-$0.01	-$0.11
WECC	694,787,895	255,116,789	29,814,787	8.56	-$426,229	$0.00	-$0.01

Table 7-4: Average Incremental Annual Cost per Household in 2020 by NERC Region and Regulatory Option (2018$)

US[b]	**3,806,416,322**	**1,492,029,155**	**140,547,123**	**10.62**	**-$25,510,674**	**-$0.01**	**-$0.07**

a. The rate impact analysis assumes full pass-through of all compliance costs to electricity consumers.

b. ELG compliance costs are zero in the AK and HICC regions and these regions are therefore omitted from the presentation. For this reason, electricity sales shown for the United States is greater than the total for NERC regions included in the table.

Sources: U.S. EPA Analysis, 2019; EIA, 2018; EIA, 2016

7.3.3 Uncertainties and Limitations

As noted above, the assumption of 100 percent pass-through of compliance costs to electricity prices represents a worst-case scenario from the perspective of households. To the extent that some steam electric power plants are not able to pass their compliance costs to consumers through higher electricity rates, this analysis overstates the potential impact of the regulatory options on households.

This analysis also assumes that costs would be passed on in the form of a flat-rate price increase per unit of electricity, an assumption the EPA deems reasonable to characterize the magnitude of compliance costs relative to household electricity consumption. The allocation of costs to the residential class could be higher or lower than estimated by this approach.

7.4 Distribution of Electricity Cost Impact on Household

In general, lower-income households spend less, in the absolute, on energy than do higher-income households, but energy expenditures represent a larger *share* of their income. Therefore, electricity price increases tend to have a relatively larger effect on lower-income households, compared to higher-income households. In analyzing the impacts of the 2015 rule, the EPA conducted a distributional analysis of the final rule to assess (1) whether an increase in electricity rates that may occur under the final rule would disproportionately affect lower-income households and (2) whether households would be able to pay for these electricity rate increases without experiencing economic hardship (*i.e.*, whether the increase is affordable). The analysis provided additional insight on the distribution of impacts among residential electricity consumers to help respond to concerns regarding the impacts of the rule on utilities and cooperatives in service areas that include a relatively high proportion of low-income households.

In the 2015 analysis, the EPA had concluded that even when looking at a worst-case scenario of 100 percent pass through of the compliance costs, the "incremental economic burden of any final rule based on the regulatory options in the proposal on households is small both relative to income and relative to the baseline energy burden of households in different income ranges. While the incremental burden relative to income is not distributionally neutral, *i.e.*, any increase would affect lower-income households to a greater extent than higher-income households, the small impacts may be further moderated by existing pricing structures (see Section 7.4 in U.S. EPA, 2015b)." As presented in the preceding sections, the EPA estimates that the four regulatory options would reduce compliance costs for FGD wastewater and bottom ash transport water when compared to the baseline. To the extent that these savings are in turn passed through to electricity consumers in the form of lower prices, the resulting lower electricity prices may have a larger positive effect on lower-income households. The EPA finds that the earlier conclusion of small impacts from the 2015 ELG still holds given the lower compliance costs of the four regulatory options, relative to the baseline.

8 Assessment of Potential Impact of the Regulatory Options on Small Entities – Regulatory Flexibility Act (RFA) Analysis

The Regulatory Flexibility Act (RFA) of 1980, as amended by the Small Business Regulatory Enforcement Fairness Act (SBREFA) of 1996, requires federal agencies to consider the impact of their rules on small entities, to analyze alternatives that minimize those impacts,[49] and to make their analyses available for public comments. The RFA is concerned with three types of small entities: small businesses, small nonprofits, and small government jurisdictions.

The RFA describes the regulatory flexibility analyses and procedures that must be completed by federal agencies unless they certify that the rule, if promulgated, would not have a significant economic impact on a substantial number of small entities. This certification must be supported by a statement of factual basis, *e.g.*, addressing the number of small entities affected by the proposed action, estimated cost impacts on these entities, and evaluation of the economic impacts.

In accordance with RFA requirements and as it has consistently done in developing effluent limitations guidelines and standards, the EPA assessed whether the regulatory options would have "a significant impact on a substantial number of small entities" (SISNOSE). Following the approach used in the analysis of the 2015 rule (U.S. EPA, 2015b), this assessment involved the following steps:

- Identifying the domestic parent entities of steam electric power plants.
- Determining which of those domestic parent entities are small entities, based on Small Business Administration (SBA) size criteria.
- Assessing the change in potential impact of the regulatory options on those small entities by comparing the estimated entity-level annualized compliance cost to entity-level revenue; the cost-to-revenue ratio indicates the magnitude of economic impacts. Following EPA guidance (U.S. EPA, 2006), the EPA used threshold compliance costs of one percent or three percent of entity-level revenue to categorize the degree of *significance* of the economic impacts on small entities.
- Assessing the change in whether those small entities incurring potentially significant impacts represent a substantial number of small entities. Following EPA guidance (U.S. EPA, 2006), the EPA determined whether the number of small entities impacted is *substantial* based on (1) the estimated *absolute numbers* of small entities incurring potentially significant impacts according to the two cost impact criteria, and (2) the *percentage of small entities* in the relevant entity categories that are estimated to incur these impacts.

The EPA performed this assessment for the baseline and each of the regulatory options, with the differences between the findings indicative of the impacts of the options on small entities. This chapter describes the analytic approach (Section 8.1), summarizes the findings of the EPA's RFA assessment

49 Section 603(c) of the RFA provides examples of such alternatives as: (1) the establishment of differing compliance or reporting requirements or timetables that take into account the resources available to small entities; (2) the clarification, consolidation, or simplification of compliance and reporting requirements under the rule for such small entities; (3) the use of performance rather than design standards; and (4) an exemption from coverage of the rule, or any part thereof, for such small entities.

(Section 8.2), and reviews uncertainties and limitations in the analysis (Section 8.3). The Chapter also discusses how regulatory options developed by the EPA served to mitigate the impact of the regulatory options on small entities (Section 8.4).

8.1 Analysis Approach and Data Inputs

The EPA used the same methodology and assumptions used for the analysis of the 2015 rule (U.S. EPA, 2015b), but updated input data to reflect more recent information about plant ownership, entity size, and compliance costs as described in the sections below.

One difference from the approach used for the 2015 rule analysis is the explicit analysis of the impacts of the baseline on small entities, which serves as contrast for analyzed impacts of the regulatory options. This two-part analysis enables the Agency to understand how the regulatory options mitigate any impacts to small entities projected under the baseline.

8.1.1 Determining Parent Entity of Steam Electric Power Plants

Consistent with the entity-level cost-to-revenue analysis (Chapter 4: Economic Impact Screening Analyses), the EPA conducted the RFA analysis at the highest level of domestic ownership, referred to as the “domestic parent entity” or “domestic parent firm”, including only entities with the largest share of ownership (majority owner)[50] in at least one of the estimated 951 steam electric power plants in the steam electric point source category. As was done for the entity-level cost-to-revenue analysis in Section 4.3, the EPA identified the majority owner for each plant using 2016 databases published by the Department of Energy’s Energy Information Administration (EIA) (EIA, 2017a), corporate and financial websites, and the Steam Electric Survey (U.S. EPA, 2010b).

8.1.2 Determining Whether Parent Entities of Steam Electric Power Plants Are Small

The EPA identified the size of each parent entity using the SBA size threshold guidelines in effect as of October 1, 2017 (SBA, 2017). The criteria for entity size determination vary by the organization/operation category of the parent entity, as follows:

- **Privately owned (non-government) entities**: Privately owned entities include investor-owned utilities, non-utility entities, and entities with a primary business other than electric power generation. For entities with electric power generation as a primary business, small entities are those with less than the threshold number of employees specified by SBA for each of the relevant North American Industry Classification System (NAICS) sectors (NAICS 2211) (see *Table 8-1*). For entities with a primary business other than electric power generation, the relevant size criteria are based on revenue or number of employees by NAICS sector. [51]

- **Publicly owned entities**: Publicly owned entities include federal, State, municipal, and other political subdivision entities. The federal and State governments were considered to be large; municipalities and other political units with population less than 50,000 were considered to be small.

50 Throughout the analyses, the EPA refers to the owner with the largest ownership share as the “majority owner” even when the ownership share is less than 51 percent.

51 Certain steam electric power plants are owned by entities whose primary business is not electric power generation.

- **Rural Electric Cooperatives**: Small entities are those with less than the threshold number of employees specified by SBA for each of the relevant NAICS sectors, depending on the type of electricity generation (see *Table 8-1*).

Table 8-1: NAICS Codes and SBA Size Standards for Non-government Majority Owners Entities of Steam Electric Power Plants

NAICS Code[a]	NAICS Description	SBA Size Standard[b]
212111	Bituminous Coal and Lignite Surface Mining	1250 Employees
221111	Hydroelectric Power Generation	500 Employees
221112	Fossil Fuel Electric Power Generation	750 Employees
221113	Nuclear Electric Power Generation	750 Employees
221114[c]	Solar Electric Power Generation	250 Employees
221115[c]	Wind Electric Power Generation	250 Employees
221116[c]	Geothermal Electric Power Generation	250 Employees
221117[c]	Biomass Electric Power Generation	250 Employees
221118[c]	Other Electric Power Generation	250 Employees
221121	Electric Bulk Power Transmission and Control	500 Employees
221122	Electric Power Distribution	1,000 Employees
221210	Natural Gas Distribution	1,000 Employees
221310	Water Supply and Irrigation Systems	$27.5 million in revenue
237130	Power and Communication Line and Related Structures Construction	$36.5 million in revenue
332410	Power Boiler and Heat Exchanger Manufacturing	750 Employees
333611	Turbine and Turbine Generator Set Unit Manufacturing	1,500 Employees
523920	Portfolio Management	$37.7 million in revenue
524113	Direct Life Insurance Carriers	$37.7 million in revenue
524126	Direct Property and Casualty Insurance Carriers	1,500 employees
541614	Process, Physical Distribution and Logistics Consulting Services	$15 million in revenue
551112	Offices of Other Holding Companies	$20.5 million in revenue
562219	Other Nonhazardous Waste Treatment and Disposal	$38.5 million in revenue

a. Certain plants affected by this rulemaking are owned by non-government entities whose primary business is not electric power generation.

b. Based on size standards effective at the time EPA conducted this analysis (SBA size standards, effective October 1, 2017).

c. NAICS code used as proxy for determining size threshold for entities categorized in NAICS 221119.

Source: SBA, 2017

To determine whether a majority owner is a small entity according to these criteria, the EPA compared the relevant entity size criterion value estimated for each parent entity to the SBA threshold value. The EPA used the following data sources and methodology to estimate the relevant size criterion values for each parent entity:

- **Employment**: The EPA used entity-level employment values from corporate/financial websites, if those values were available, or from the Steam Electric Survey if more recent data were not available.

- **Revenue**: The EPA used entity-level revenue values described in Section 4.3.1. For entities with values reported for more than one year, the EPA used the average of reported values.

- **Population**: Population data for municipalities and other non-state political subdivisions were obtained from the U.S. Census Bureau (estimated population for 2016) (U.S. DOC, 2016).

Parent entities for which the relevant measure is less than the SBA size criterion were identified as small entities and carried forward in the RFA analysis.

As discussed in Chapter 4 (Economic Impact Screening Analyses), the EPA estimated the number of small entities owning steam electric power plants as a range, based on alternative assumptions about the possible ownership of electric power plants that fall within the definition of the point source category. Following the approach used in the analysis of the 2015 rule, the EPA analyzed two cases that provide a range of estimates for (1) the number of firms incurring compliance costs and (2) the costs incurred by any firm owning a regulated plant (U.S. EPA, 2015b).

Table 8-2 presents the total number of entities with steam electric power plants as well as the number and percentage of those entities determined to be small. Table 8-3 presents the distribution of steam electric power plants by ownership type and owner size. Analysis results are presented by ownership type for the baseline and the four analyzed regulatory options under the lower (Case 1) and upper (Case 2) bound estimates of the number of entities owning steam electric power plants.

As reported in Table 8-2 and Table 8-3, the EPA estimates that between 243 and 478 entities own 951 steam electric power plants (for Case 1 and Case 2, respectively).[52] A typical parent entity on average is estimated to own four steam electric power plants (for both Case 1 and Case 2). The Agency estimates that between 79 (36 percent) and 127 (27 percent) parent entities are small (Table 8-2), and these small entities own 139 steam electric power plants (Table 8-3), or approximately 15 percent of all steam electric power plants. Across ownership types, cooperatives represent the largest share of small entities (75 and 72 percent, for Case 1 and Case 2 respectively); cooperatives account for the largest share of steam electric power plants owned by small entities (64 percent).

[52] As described in Chapter 8 in the 2015 RIA document (U.S. EPA, 2015b), Case 1 assumed that any entity owning a surveyed plant(s) owns the known surveyed plant(s) and all of the sample weight associated with the surveyed plant(s). This case minimizes the count of affected entities, while tending to maximize the potential cost burden to any single entity. Case 2 assumed (1) that an entity owns only the surveyed plant(s) that it is known to own from the Steam Electric Survey and (2) that this pattern of ownership, observed for surveyed plants and their owning entities, extends over the entire plant population. This case minimizes the possibility of multi-plant ownership by a single entity and thus maximizes the count of affected entities, but also minimizes the potential cost burden to any single entity.

Table 8-2: Number of Entities by Sector and Size (assuming two different ownership cases)

Ownership Type	Small Entity Size Standard	Case 1: Lower bound estimate of number of entities owning steam electric power plants [a,b]			Case 2: Upper bound estimate of number of entities owning steam electric power plants [a,b]		
		Total	Small	% Small	Total	Small	% Small
Cooperative	number of employees	28	21	75.0%	50	36	72.2%
Federal	assumed large	1	0	0.0%	3	0	0.0%
Investor-owned	number of employees[d]	69	9	13.0%	157	20	13.0%
Municipality	50,000 population served	59	29	49.2%	94	37	39.1%
Nonutility	number of employees[d]	74	19	25.7%	150	33	22.0%
Other Political Subdivision[c]	50,000 population served	10	1	10.0%	21	1	4.7%
State	assumed large	2	0	0.0%	2	0	0.0%
Total		**243**	**79**	**32.5%**	**478**	**127**	**26.6%**

a. Thirteen plants are owned by a joint venture of two entities.

b. Of these, 58 entities, 15 of which are small, own steam electric power plants that are estimated to incur compliance technology costs under regulatory options under both Case 1 and Case 2.

c. The EPA was unable to determine the size of one parent entity owned by a political subdivision; for this analysis, this entity is assumed to be large.

d. Entity size may be based on revenue, depending on the NAICS sector (see *Table 8-1*).

Source: U.S. EPA Analysis, 2019.

Table 8-3: Steam Electric Power Plants by Ownership Type and Size

Ownership Type	Small Entity Size Standard	Number of Steam Electric Power Plants[a,b,c,d]		
		Total	Small	% Small
Cooperative	number of employees	64	41	64.2%
Federal	assumed large	20	0	0.0%
Investor-owned	number of employees[e]	509	22	4.4%
Municipality	50,000 population served	123	37	30.1%
Nonutility	number of employees[e]	198	38	19.2%
Other Political Subdivisions	50,000 population served	34	1	3.0%
State	assumed large	4	0	0.0%
Total		**951**	**139**	**14.7%**

a. Numbers may not add up to totals due to independent rounding.

b. The numbers of plants and capacity are calculated on a sample-weighted basis.

c. Plant size was determined based on the size of the owner with the largest share in the plant. In case of multiple owners with equal ownership shares (*e.g.*, two entities with 50/50 shares), a plant was assumed to be small if it is owned by at least one small entity.

d. Of these, 114 steam electric power plants are estimated to incur compliance costs under the baseline, whereas 108 plants incur compliance costs under the regulatory options; 15 of the 108 steam electric power plants are owned by small entities.

e. Entity size may be based on revenue, depending on the NAICS sector (see *Table 8-1*).

Source: U.S. EPA Analysis, 2019.

8.1.3 Significant Impact Test for Small Entities

As outlined in the introduction to this chapter, two criteria are assessed in determining whether the regulatory options would qualify for a no-SISNOSE finding:

- Is the *absolute number* of small entities estimated to incur a potentially significant impact, as described above, *substantial*?

and

- Do these *significant impact* entities represent a *substantial* fraction of small entities in the electric power industry that could potentially be within the scope of a regulation?

A measure of the potential impact of the regulatory options on small entities is the fraction of small entities that have the potential to incur a significant impact. For example, if a high percentage of potentially small entities incur significant impacts *even though the absolute number of significant impact entities is low*, then the rule could represent a substantial burden on small entities.

To assess the extent of economic/financial impact on small entities, the EPA compared estimated compliance costs to estimated entity revenue (also referred to as the "sales test"). The analysis is based on the ratio of estimated annualized after-tax compliance costs to annual revenue of the entity. For this analysis, the EPA categorized entities according to the magnitude of economic impacts that entities would incur as a result of the regulatory options. The EPA identified entities for which annualized compliance costs are at least one percent and three percent of revenue. The EPA then evaluated the absolute number and the percent of entities in each impact category, and by type of ownership. The Agency assumed that entities incurring costs below one percent of revenue are unlikely to face significant economic impacts, while entities with costs of at least one percent of revenue have a higher chance of facing significant economic impacts, and entities incurring costs of at least three percent of revenue have a still higher probability of significant economic impacts. Consistent with the parent-level cost-to-revenue analysis discussed in *Chapter 4*, the EPA assumed that steam electric power plants, and consequently, their parents, would not be able to pass any of the increase in their production costs to consumers (zero cost pass-through). This assumption is used for analytic convenience and provides a worst-case scenario of regulatory impacts to steam electric power plants.

A detailed summary of how EPA developed these entity-level compliance cost and revenue values is presented in *Chapter 3* and *Chapter 4*.

8.2 Key Findings for Regulatory options

As described above, the EPA developed estimates of the number of small parent entities in the specified cost-to-revenue impact ranges. Table 8-4 and Table 8-5 summarize the results of the analysis, with Table 8-4 showing baseline results and Table 8-5 showing incremental results of the four options relative to this baseline. In terms of *number* of entities in each of the impact categories, analysis results for each option are the same under Case 1 and Case 2; however, these numbers represent different percentages of all small entities owning steam electric power plants under each weighting case.

In the baseline, the EPA estimates that 4 small entities owning steam electric power plants, all small municipalities, would incur costs exceeding one percent of revenue (Table 8-4). The analysis shows no small business entity or small entity in other categories incurring costs greater than one percent of revenue under the baseline. On the basis of *percentage*, the four small municipalities represent approximately 11 to 14 percent of the number of small municipalities owning steam electric power plants and 3 to 5 percent of the total number of small entities owning steam electric power plants. For 2 of the 4 municipalities (5 to 7 percent of the number of small municipalities owning steam electric power plants) costs are estimated to exceed three percent of revenue.

Under Option 2, relative to the baseline 2 fewer small entities would incur costs exceeding one percent of revenue, and 1 fewer small entity would incur costs exceeding three percent of revenue (Table 8-5). Under the other three options, 1 fewer small entity would incur costs exceeding one percent of revenue, and no change is estimated for the number of plants incurring costs greater than three percent of revenue.

On the basis of *percentage* of small entities by entity type across the range of owning entities, the analysis of Option 2, shows 5 to 7 percent fewer small government entities incurring costs greater than one percent of revenue, while under the other three options, which have the same results, approximately 3 percent fewer small government entities incur costs greater than one percent of revenue (Table 8-5).

This screening-level analysis suggests that the baseline is unlikely to have a significant economic impact on a substantial impact on small entities. And because the regulatory options reduce this impact further by providing cost savings to many small entities, the same conclusion can be reached for the four regulatory options the EPA analyzed.

Table 8-4: Estimated Baseline Cost-To-Revenue Impact on Small Parent Entities, by Entity Type and Ownership Category

Entity Type/Ownership Category	Case 1: Lower bound estimate of number of entities owning steam electric power plants (out of total of 79 small entities)				Case 2: Upper bound estimate of number of entities owning steam electric power plants (out of total of 127 small entities)			
	≥1%		≥3%[a]		≥1%		≥3%[a]	
	Number of small entities	% of all small entities[b]	Number of small entities	% of all small entities[b]	Number of small entities	% of all small entities[b]	Number of small entities	% of all small entities[b]
Baseline								
Small Business								
Cooperative	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Investor-Owned	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Nonutility	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Small Government								
Municipality	4	13.8%	2	6.9%	4	10.8%	2	5.4%
Political Subdivision	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	**4**	**5.1%**	**2**	**2.5%**	**4**	**3.1%**	**2**	**1.6%**

a. The number of entities with cost-to-revenue impact of at least three percent is a subset of the number of entities with such ratios exceeding one percent.

b. Percentage values were calculated relative to the total of 79 (Case 1) and 127 (Case 2) small entities owning steam electric power plants regardless of whether these plants are estimated to incur compliance technology costs under any of the regulatory options.

Source: U.S. EPA Analysis, 2019

Table 8-5: Estimated Incremental Cost-To-Revenue Impact on Small Parent Entities, by Entity Type and Ownership Category

Entity Type/Ownership Category	Case 1: Lower bound estimate of number of entities owning steam electric power plants (out of total of 79 small entities)				Case 2: Upper bound estimate of number of entities owning steam electric power plants (out of total of 127 small entities)			
	≥1%		≥3%[a]		≥1%		≥3%[a]	
	ΔNumber of small entities	Δ% of all small entities[b]	ΔNumber of small entities	Δ% of all small entities[b]	ΔNumber of small entities	Δ% of all small entities[b]	ΔNumber of small entities	Δ% of all small entities[b]
Option 1								
Small Business								
Cooperative	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Investor-Owned	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Nonutility	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Small Government								
Municipality	-1	-3.4%	0	0.0%	-1	-2.7%	0	0.0%
Political Subdivision	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	**-1**	**-1.3%**	**0**	**0.0%**	**-1**	**-0.8%**	**0**	**0.0%**
Option 2								
Small Business								
Cooperative	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Investor-Owned	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Nonutility	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Small Government								
Municipality	-2	-6.9%	-1	-3.4%	-2	-5.4%	-1	-2.7%
Political Subdivision	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	**-2**	**-2.5%**	**-1**	**-1.3%**	**-2**	**-1.6%**	**-1**	**-0.8%**
Option 3								
Small Business								
Cooperative	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Investor-Owned	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Nonutility	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Small Government								
Municipality	-1	-3.4%	0	0.0%	-1	-2.7%	0	0.0%
Political Subdivision	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	**-1**	**-1.3%**	**0**	**0.0%**	**-1**	**-0.8%**	**0**	**0.0%**

Table 8-5: Estimated Incremental Cost-To-Revenue Impact on Small Parent Entities, by Entity Type and Ownership Category

Entity Type/Ownership Category	Case 1: Lower bound estimate of number of entities owning steam electric power plants (out of total of 79 small entities)				Case 2: Upper bound estimate of number of entities owning steam electric power plants (out of total of 127 small entities)			
	≥1%		≥3%[a]		≥1%		≥3%[a]	
	ΔNumber of small entities	Δ% of all small entities[b]	ΔNumber of small entities	Δ% of all small entities[b]	ΔNumber of small entities	Δ% of all small entities[b]	ΔNumber of small entities	Δ% of all small entities[b]
Option 4								
Small Business								
Cooperative	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Investor-Owned	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Nonutility	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Small Government								
Municipality	-1	-3.4%	0	0.0%	-1	-2.7%	0	0.0%
Political Subdivision	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	**-1**	**-1.3%**	**0**	**0.0%**	**-1**	**-0.8%**	**0**	**0.0%**

a. The number of entities with cost-to-revenue impact of at least three percent is a subset of the number of entities with such ratios exceeding one percent.

b. Percentage values were calculated relative to the total of 79 (Case 1) and 127 (Case 2) small entities owning steam electric power plants regardless of whether these plants are estimated to incur compliance technology costs under any of the regulatory options.

Source: U.S. EPA Analysis, 2019

8.3 Uncertainties and Limitations

Despite the EPA's use of the best available information and data, the RFA analysis discussed in this chapter has sources of uncertainty, including:

- None of the sample-weighting approaches used for this analysis accounts precisely for the number of parent-entities and compliance costs assigned to those entities simultaneously. The EPA assesses the values presented in this chapter as reasonable estimates of the numbers of small entities that could incur a significant impact according to the cost-to-revenue metric.

- In cases where available information was insufficient to determine the size of an entity, the Agency generally assumed the entity to be small, with one exception. As noted in Table 8-2, the EPA assumed one entity owned by a political subdivision to be large based on publicly available information about the entity's identified assets. However, this large entity does not incur compliance costs under the baseline or any of the four regulatory options and therefore the assumption only affects the total number of entities in each size category (*i.e.*, denominator used to estimate the percent of entities).

- As discussed in Chapter 4, the zero cost pass-through assumption represents a worst-case scenario from the perspective of the plants and parent entities. To the extent that some entities are able to pass at least some compliance costs to consumers through higher electricity prices, this analysis overstates potential impact of the regulatory options on small entities and affect the assessment of incremental effects of the regulatory options, although it would not affect the direction of those effects.

8.4 Small Entity Considerations in the Development of Rule Options

As described in the introduction to this Chapter, the RFA requires federal agencies to consider the impact of their regulatory actions on small entities and to analyze alternatives that minimize those impacts. Although the EPA presents four regulatory options which would all reduce impacts to small entities, the proposed option is the least costly option presented, and thus would result in the lowest impacts to small entities. Furthermore, subcategories for low utilization and end of life units include units owned by small entities. Furthermore, as the EPA explicitly states in the proposal, the implementation period built into the regulatory options is another way for permit writers to consider the needs of small entities, as these entities may need additional time to plan and finance capital improvements.

9 Unfunded Mandates Reform Act (UMRA) Analysis

Title II of the Unfunded Mandates Reform Act of 1995, Pub. L. 104-4, requires that federal agencies assess the effects of their regulatory actions on State, local, and Tribal governments and the private sector. Under UMRA section 202, the EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with "Federal mandates" that might result in expenditures by State, local, and Tribal governments, in the aggregate, or by the private sector, of $100 million (adjusted annually for inflation) or more in any one year (*i.e.*, $160 million in 2018 dollars). Before promulgating a regulation for which a written statement is needed, UMRA section 205 generally requires the EPA to "identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective, or least burdensome alternative that achieves the objectives of the rule." (2 U.S.C. 1535(a) The provisions of section 205 do not apply when they are inconsistent with applicable law. Moreover, section 205 allows the EPA to adopt an alternative other than the least costly, most cost-effective, or least burdensome alternative, if the Administrator publishes with the rule an explanation of why that alternative was not adopted. Before the EPA establishes any regulatory requirements that might significantly or uniquely affect small governments, including Tribal governments, it must develop a small government agency plan, under UMRA section 203. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of the EPA regulatory proposals with significant intergovernmental mandates, and informing, educating, and advising small governments on compliance with regulatory requirements.

The EPA estimated the incremental costs for compliance with the regulatory options for different categories of entities. All four regulatory options analyzed by the EPA result in lower compliance costs (cost savings) when compared to the baseline. The Agency estimates that the *maximum* incremental cost *in any one year* to government entities (excluding federal government) range from -$23.5 million under Option 1 to -$6.0 million under Option 4.[53,54] The *maximum* incremental cost *in any given year* to the private sector range from -$444.5 million under Option 4 to -$327.5 million under Option 1. From these incremental cost values, the EPA determined that the proposed rule does not contain a federal mandate that may result in expenditures of $160 million (in 2018 dollars) or more for State, local, and Tribal governments, in the aggregate, or the private sector in any one year, and in any case the proposed option (Option 2) is the least costly option presented.

This chapter contains additional information to support that statement, including information on compliance and administrative costs, and on impacts to small governments. Following the approach used for the analysis of the 2015 rule (see Chapter 9 in U.S. EPA, 2015b), the annualized costs presented in this UMRA analysis are calculated using the social cost framework presented in Chapter 12 of the BCA document (U.S. EPA, 2019b). Specifically, this analysis uses costs in 2020 stated in 2018 dollars and accounts for costs in the year they are anticipated to be incurred between 2021 and 2047. Non-recurring costs are annualized over a 27-year period. As discussed in Chapter 10 (Other Administrative Requirements; see Section 10.7) in this document, the regulatory options would not change the reporting and recordkeeping burden for the review, oversight, and administration of the rule relative to baseline

[53] Maximum costs are costs incurred by the entire universe of steam electric power plants in a given year of occurrence under a given regulatory option. For all regulatory options, these maximum costs are smaller than the maximum costs projected under the baseline, resulting in net cost savings.

[54] For this analysis, rural electric cooperatives are considered to be a part of the private sector.

requirements; consequently, NPDES permitting authorities are estimated to see no change in costs to administer this rule. The only change in cost that government entities would potentially incur as the result of this rule is that associated with the cost to implement control technologies at power plants they own. For more details on how social costs were developed, see Chapter 12 in the BCA document.

9.1 UMRA Analysis of Impact on Government Entities

This part of the UMRA analysis assesses the compliance cost burden to State, local, and Tribal governments that own existing steam electric power plants. The use of the phrase "government entities" in this section does *not* include the federal government, which owns 20 of the 951 steam electric power plants; four of these plants incur compliance costs under the regulatory options. Additionally, in evaluating the magnitude of the impact of the options on government entities, the EPA considered only *compliance costs* incurred by government entities owning steam electric power plants. Government entities would not incur significant incremental *administrative costs* to implement the rule, regardless of whether or not they own steam electric power plants.

Table 9-1 summarizes the number of State, local and Tribal government entities and the number of steam electric power plants they own. The determination of owning entities, their type, and their size is detailed in Chapter 4 (Cost and Economic Impact Screening Analyses) and Chapter 8 (Assessment of Potential Impact of the Regulatory Options on Small Entities – Regulatory Flexibility Act (RFA) Analysis).

Table 9-1: Government-Owned Steam Electric Power Plants and Their Parent Entities

Entity Type	Parent Entities[a]	Steam electric power plants[b]
Municipality	59	123
Other Political Subdivision	10	34
State	2	4
Tribal	0	0
Total	**71**	**160**

a. Counts of entities under weighting Case 1, which provides an upper bound of total compliance costs for any given parent entity. For details see *Chapter 8*.

b. Plant counts are relative to the estimated 951 plants covered under the point source category.

Source: U.S. EPA Analysis, 2019

Out of 951 steam electric power plants, 160 are owned by 71 government entities.[55] The majority (77 percent) of these government-owned plants are owned by municipalities, followed by other political subdivisions (21 percent), and State governments (2 percent).

All four regulatory options result in government entities incurring lower compliance costs compared to the baseline. Table 9-2 shows compliance costs for government entities owning steam electric power plants. Compliance costs to government entities under the baseline are approximately $37.8 million in the aggregate, with an average of $0.2 million per plant. As shown in Table 9-3, which shows the difference between the options and the baseline, all four regulatory options by comparison provide cost savings to

55 Counts exclude federal government entities and steam electric power plants they own. The owning entity is determined based on the entity with the largest ownership share in each plant, as described in Chapter 4.

government owned plants. The estimated pre-tax savings range from $5.5 million (Option 4) to $24.9 million (Option 2), with most of the aggregate savings going to municipalities. The maximum annualized compliance costs estimated to be incurred by any single government-owned plant is also generally lower under the regulatory options, with the sole exceptions being municipality and state-owned plants under Option 4 which have greater maximum costs, at $6.2 million and $4.0 million respectively, than the maximum costs projected under the baseline ($4.7 million and $3.8 million).

Table 9-2: Estimated Compliance Costs to Government Entities Owning Steam Electric Power Plants (Millions; 2018$)

Ownership Type	Number of Steam Electric Power Plants (weighted)[a]	Total Weighted, Annualized Pre-Tax Cost[a]	Average Annualized Cost per MW of Capacity[b]	Average Annualized Cost per Plant[c]	Maximum Annualized Cost per Plant[d]
Baseline					
Municipality	123	$29.5	$643	$0.2	$4.7
Other Political Subdivision	34	$1.5	$53	$0.0	$1.5
State	4	$6.7	$1,405	$1.7	$3.8
Total	**160**	**$37.8**	**$476**	**$0.2**	**$4.7**
Option 1					
Municipality	123	$19.0	$414	$0.2	$3.1
Other Political Subdivision	34	$1.2	$41	$0.0	$1.2
State	4	$2.4	$499	$0.6	$2.3
Total	**160**	**$22.6**	**$285**	**$0.1**	**$3.1**
Option 2					
Municipality	123	$11.0	$240	$0.1	$3.2
Other Political Subdivision	34	$0.0	$1	$0.0	$0.0
State	4	$1.9	$387	$0.5	$1.8
Total	**160**	**$12.9**	**$163**	**$0.1**	**$3.2**
Option 3					
Municipality	123	$21.0	$457	$0.2	$3.2
Other Political Subdivision	34	$1.2	$41	$0.0	$1.2
State	4	$3.0	$635	$0.8	$1.8
Total	**160**	**$25.2**	**$318**	**$0.2**	**$3.2**
Option 4					
Municipality	123	$25.1	$547	$0.2	$6.2
Other Political Subdivision	34	$1.2	$41	$0.0	$1.2
State	4	$6.0	$1,258	$1.5	$4.0
Total	**160**	**$32.3**	**$408**	**$0.2**	**$6.2**

a. Plant counts are relative to the estimated 951 plants covered under the point source category.

b. Average cost per MW values were calculated using total compliance costs and capacity for all steam electric power plants owned by entities in a given ownership category. In case of multiple ownership structure where parent entities of a given plant have equal ownership shares and are in different ownership categories, compliance costs and capacity were allocated to appropriate ownership categories in accordance with ownership shares.

c. Average cost per plant values were calculated using the total number of steam electric power plants owned by entities in a given ownership category.

d. Reflects maximum of un-weighted costs to surveyed plants only.

Source: U.S. EPA Analysis, 2019.

Table 9-3: Estimated Incremental Compliance Costs to Government Entities Owning Steam Electric Power Plants (Millions; 2018$)

Ownership Type	Number of Steam Electric Power Plants (weighted)[a]	Total Weighted, Annualized Pre-Tax Cost[a]	Average Annualized Cost per MW of Capacity[b]	Average Annualized Cost per Plant[c]	Maximum Annualized Cost per Plant[d]
Option 1					
Municipality	123	-$10.5	-$230	-$0.1	-$1.6
Other Political Subdivision	34	-$0.3	-$12	$0.0	-$0.3
State	4	-$4.3	-$906	-$1.1	-$1.5
Total	**160**	**-$15.2**	**-$192**	**-$0.1**	**-$1.6**
Option 2					
Municipality	123	-$18.5	-$403	-$0.2	-$1.5
Other Political Subdivision	34	-$1.5	-$52	$0.0	-$1.5
State	4	-$4.9	-$1,018	-$1.2	-$2.0
Total	**160**	**-$24.9**	**-$314**	**-$0.2**	**-$1.5**
Option 3					
Municipality	123	-$8.5	-$186	-$0.1	-$1.5
Other Political Subdivision	34	-$0.3	-$12	$0.0	-$0.3
State	4	-$3.7	-$769	-$0.9	-$2.0
Total	**160**	**-$12.6**	**-$158**	**-$0.1**	**-$1.5**
Option 4					
Municipality	123	-$4.4	-$96	$0.0	$1.5
Other Political Subdivision	34	-$0.3	-$12	$0.0	-$0.3
State	4	-$0.7	-$146	-$0.2	$0.2
Total	**160**	**-$5.5**	**-$69**	**$0.0**	**$1.5**

a. Plant counts are relative to the estimated 951 plants covered under the point source category.

b. Average cost per MW values were calculated using total compliance costs and capacity for all steam electric power plants owned by entities in a given ownership category. In case of multiple ownership structure where parent entities of a given plant have equal ownership shares and are in different ownership categories, compliance costs and capacity were allocated to appropriate ownership categories in accordance with ownership shares.

c. Average cost per plant values were calculated using the total number of steam electric power plants owned by entities in a given ownership category.

d. Reflects maximum of un-weighted costs to surveyed plants only.

Source: U.S. EPA Analysis, 2019.

9.2 UMRA Analysis of Impact on Small Governments

As part of the UMRA analysis, the EPA also assessed whether the regulatory options would significantly and uniquely affect small governments. To assess whether the regulatory options would affect small governments in a way that is disproportionately burdensome in comparison to the effect on large governments, the EPA compared total incremental costs and costs per plant estimated to be incurred by small governments with those values estimated to be incurred by large governments. The EPA also compared the changes in per plant costs incurred for small government-owned plants with those incurred by non-government-owned plants. The Agency evaluated costs per plant on the basis of both average and maximum annualized incremental cost per plant.

Out of 161 government-owned steam electric power plants, the EPA identified 38 plants that are owned by 30 small government entities. These 38 plants constitute approximately 24 percent of all government-owned plants.[56]

Table 9-4: Counts of Government-Owned Plants and Their Parent Entities, by Size

Entity Type	Entities[a]			Steam Electric Power Plants[b]		
	Large	Small	Total	Large	Small	Total
Municipality	30	29	59	86	37	123
Other Political Subdivision	9	1	10	33	1	34
State	2	0	2	4	0	4
Total	**41**	**30**	**71**	**123**	**38**	**161**

a. Counts of entities under weighting Case 1, which provides an upper bound of total compliance costs for any given parent entity. For details see *Chapter 8*.

b. Plant counts are relative to the estimated 951 plants covered under the point source category.

Source: U.S. EPA Analysis, 2019.

All four regulatory options result in small government entities incurring lower compliance costs compared to the baseline. As presented in Table 9-5, overall compliance cost savings are greatest under Option 2 and smallest under Option 4, but the distribution of cost savings among different entity categories and sizes is not uniform. For Options 1, 2, and 3, aggregate compliance cost savings are the largest for large private entities, followed by large governments, small private entities, and small governments. Option 4, by contrast, results in lower costs incurred by governments (large and small) and small private entities, but increased compliance costs for large private entities. On a per MW basis, small governments are projected to see larger cost savings – as much as $2,103 per MW under Option 2 – than large governments or private entities. Because plants owned by small governments tend to be smaller compared to those owned by large governments or small private entities, the same is not necessarily true on a per plant basis under Options 1 and 3. Given these results, the EPA finds that small governments would not be significantly or uniquely affected by the regulatory options.

Table 9-5: Estimated Incremental Compliance Costs for Electric Generators by Ownership Type and Size (2018$)

Ownership Type	Entity Size	Number of Plants [a]	Total Annualized Pre-Tax Costs (Millions)[a]	Average Annualized Pre-tax Cost per MW of Capacity[b]	Average Annualized Pre-tax Cost per Plant (Millions)[c]	Maximum Annualized Pre-tax Cost per Plant (Millions)
			Option 1			
Government (excl. federal)	Small	38	-$2.8	-$627	-$0.07	-$1.0
	Large	122	-$12.4	-$166	-$0.10	-$2.4
Private	Small	101	-$8.6	-$252	-$0.08	-$1.7
	Large	669	-$105.4	-$186	-$0.14	-$2.9
All Plants		**951**	**-$154.0**	**-$218**	**-$0.15**	**-$15.7**

56 Counts exclude federal government entities and steam electric power plants they own.

Table 9-5: Estimated Incremental Compliance Costs for Electric Generators by Ownership Type and Size (2018$)

Ownership Type	Entity Size	Number of Plants [a]	Total Annualized Pre-Tax Costs (Millions)[a]	Average Annualized Pre-tax Cost per MW of Capacity[b]	Average Annualized Pre-tax Cost per Plant (Millions)[c]	Maximum Annualized Pre-tax Cost per Plant (Millions)
Option 2						
Government (excl. federal)	Small	38	-$9.4	-$2,103	-$0.25	-$2.4
	Large	122	-$15.4	-$206	-$0.13	-$1.5
Private	Small	101	-$11.0	-$320	-$0.10	-$2.5
	Large	669	-$106.1	-$187	-$0.14	-$1.7
All Plants		**951**	**-$166.2**	**-$235**	**-$0.16**	**-$15.7**
Option 3						
Government (excl. federal)	Small	38	-$3.6	-$792	-$0.09	-$1.3
	Large	122	-$9.0	-$120	-$0.07	-$1.5
Private	Small	101	-$7.4	-$217	-$0.07	-$2.2
	Large	669	-$75.4	-$133	-$0.10	-$1.7
All Plants		**951**	**-$119.5**	**-$169**	**-$0.12**	**-$15.7**
Option 4						
Government (excl. federal)	Small	38	-$3.2	-$712	-$0.08	-$1.2
	Large	122	-$2.3	-$30	-$0.02	$1.5
Private	Small	101	-$4.0	-$116	-$0.04	-$2.0
	Large	669	$1.6	$3	$0.00	$0.6
All Plants		**951**	**-$27.3**	**-$39**	**-$0.03**	**-$15.7**

a. Plant counts are relative to the estimated 951 plants covered under the point source category.

b. Average cost per MW values were calculated using total compliance costs and capacity for all steam electric power plants owned by entities in a given ownership category, *including plants that incur zero costs*. In case of multiple ownership structure where parent entities of a given plant have equal ownership shares and are in different ownership categories, compliance costs and capacity were allocated to appropriate ownership categories in accordance with ownership shares.

c. Average cost per plant values were calculated using total number of steam electric power plants owned by entities in a given ownership category. As a result, plants with multiple majority owners are represented more than once in the denominator of relevant cost per plant calculations.

Source: U.S. EPA Analysis, 2019.

9.3 UMRA Analysis of Impact on the Private Sector

As the final part of the UMRA analysis, this section reports the compliance costs projected to be incurred by private entities.

Table 9-6 summarizes the total annualized costs, maximum one-year costs, and the year when maximum costs are incurred by type of owner. As shown in the last two columns of the table, the four options result in cost savings, both on an annualized basis and for the maximum one-year costs, when compared to the baseline. The EPA estimates the incremental annualized pre-tax compliance costs for private entities to range from -$117.0 million under Option 2 to -$2.4 million under Option 4.

Table 9-6: Compliance Costs for Electric Generators by Ownership Type (2018$)

Ownership Type	Total Annualized Costs	Maximum One-Year Costs	Year of Maximum Costs[a]	Incremental Annualized Costs Relative to Baseline	Incremental Maximum One-Year Costs Relative to Baseline[b]
Baseline					
Government (excl. federal)	$37.8	$44.1	2022	NA	NA
Private	$311.0	$841.3	2023	NA	NA
Option 1					
Government (excl. federal)	$22.6	$20.5	2021	-$15.2	-$23.5
Private	$197.0	$513.8	2023	-$114.0	-$327.5
Option 2					
Government (excl. federal)	$12.9	$21.1	2028	-$24.9	-$23.0
Private	$194.0	$436.4	2023	-$117.0	-$405.0
Option 3					
Government (excl. federal)	$25.2	$22.5	2028	-$12.6	-$21.6
Private	$228.2	$438.2	2023	-$82.8	-$403.1
Option 4					
Government (excl. federal)	$32.3	$38.1	2027	-$5.5	-$6.0
Private	$308.6	$396.8	2023	-$2.4	-$444.5

NA: Not applicable for the baseline.

a. The year when the maximum cost occurs is driven by the modeled technology implementation schedule and is determined based on the renewal of individual NPDES permits for plants owned by the different categories of entities. See Section 3.1.3 in this report and BCA *Chapter 11* for more details on the technology implementation years and assumptions on the timing of cost incurrence.

b. The maximum one-year cost does not necessarily occur on the same year for a given plant across all the options analyzed. For the purpose of comparing the regulatory options to the baseline, the EPA used the maximum costs in any year rather than comparing costs on a year-to-year basis to obtain the maximum difference.

Source: U.S. EPA Analysis, 2019.

9.4 UMRA Analysis Summary

The EPA estimates that none of the regulatory options would result in incremental expenditures of at least $160 million for State and local government entities, in the aggregate, or for the private sector in any one year. In fact, all four regulatory options provide net cost savings when compared to the baseline. Furthermore, as discussed above, neither permitted plants nor permitting authorities are estimated to incur significant additional administrative costs as the result of the regulatory options.

Consistent with Section 205, the EPA presents four regulatory options which would all reduce impacts to governments and the private sector. The proposed option (Option 2) is the least costly option presented, and thus would result in the lowest impacts to governments and the private sector. Furthermore, several government and private sector plants would likely fall into subcategories which would provide additional flexibility. Finally, the implementation period built into the regulatory options is another way for permit writers to consider the site-specific needs of steam electric power plants.

10 Other Administrative Requirements

This chapter presents analyses conducted in support of the regulatory options to address the requirements of applicable Executive Orders and Acts. These analyses complement EPA's assessment of the compliance costs, economic impacts, and economic achievability of the proposed ELG revisions, and other analyses done in accordance with the RFA and UMRA, presented in previous chapters.

10.1 Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

Under Executive Order (E.O.) 12866 (58 FR 51735, October 4, 1993), the EPA must determine whether the regulatory action is "significant" and therefore subject to review by the Office of Management and Budget (OMB) and other requirements of the Executive Order. The order defines a "significant regulatory action" as one that is likely to result in a regulation that 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; or
- Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency; or
- Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or
- Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

Executive Order 13563 (76 FR 3821, January 21, 2011) was issued on January 18, 2011. This Executive Order supplements Executive Order 12866 by outlining the President's regulatory strategy to support continued economic growth and job creation, while protecting the safety, health and rights of all Americans. Executive Order 13563 requires considering costs, reducing burdens on businesses and consumers, expanding opportunities for public involvement, designing flexible approaches, ensuring that sound science forms the basis of decisions, and retrospectively reviewing existing regulations.

Pursuant to the terms of Executive Order 12866, the EPA determined that the proposed rule is an "economically significant regulatory action" because the action is likely to have an annual effect on the economy of $100 million or more, although the direction of the effect is estimated to be a *reduction* in costs when compared to the baseline. As such, the action is subject to review by OMB under Executive Orders 12866 and 13563. Any changes made in response to OMB suggestions or recommendations will be documented in the docket for this action.

The EPA prepared an analysis of the potential benefits and costs associated with this action; this analysis is described in Chapter 13 of the BCA document (U.S. EPA, 2019b).

As detailed in earlier chapters of this report, the EPA also assessed the impacts of the regulatory options on the wholesale price of electricity (Chapter 5: Electricity Market Analyses), retail electricity prices by consumer group (Chapter 7: Electricity Price Effects), and on employment or labor markets (Chapter 6: Employment Effects).

10.2 Executive Order 13771: Reducing Regulation and Controlling Regulatory Costs

The proposed rule, when finalized, would be considered a deregulatory action under E.O. 13771, Reducing Regulation and Controlling Regulatory Costs. As presented in *Chapter 3* (Table 3-3), all four regulatory options analyzed have total compliance costs less than zero, when compared to the baseline. Accounting for the timing of the costs shows net social cost savings for all four options using a 7 percent discount rate, and options 1, 2, and 3 using a 3 percent discount rate. See Chapter 12 in the BCA document (U.S. EPA, 2019b) for details on the time profile of costs and annualized discounted costs.

10.3 Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations

E.O. 12898 (59 FR 7629, February 11, 1994) requires that, to the greatest extent practicable and permitted by law, each Federal agency must make the achievement of environmental justice (EJ) part of its mission. E.O. 12898 provides that each Federal agency must conduct its programs, policies, and activities that substantially affect human health or the environment in a manner that ensures such programs, policies, and activities do not have the effect of (1) excluding persons (including populations) from participation in, or (2) denying persons (including populations) the benefits of, or (3) subjecting persons (including populations) to discrimination under such programs, policies, and activities because of their race, color, or national origin.

To meet the objectives of E.O. 12898 and consistent with the EPA guidance on considering EJ in the development of regulatory actions (U.S. EPA, 2015c), the EPA examined whether the benefits from the regulatory options may be differentially distributed among population subgroups in the affected areas. As described in Chapter 14 of the BCA document (U.S. EPA, 2019b) and building on the approach EPA used in analyzing the 2015 rule, the EPA conducted three analyses to evaluate the EJ implications of the proposed rule: (1) summarizing the demographic characteristics of individuals living in proximity to steam electric power plants and thus are likely to be affected by the plant discharges and changes in air emissions resulting from the proposed ELG (2) summarizing the demographic characteristics of individuals served by public water systems (PWS) downstream from steam electric power plants and potentially affected by bromide discharges, and (3) analyzing the human health impacts from consuming self-caught fish on minority and/or low-income populations, as well as subsistence fishers.

Based on these EJ analyses, the EPA determined that the majority of impacted communities at the census block, county, and tribal area levels are not poorer or more minority than national averages, but are when compared to state averages. Therefore, the regulatory options could benefit or harm populations with EJ concerns depending on each option’s pollutant exposure potential. The EPA determined that the regulatory options would not deny communities from the benefits of environmental improvements estimated to result from compliance with the more stringent effluent limits, but the options may disproportionally affect communities in cases where the rule may result in small increases in pollutant exposure compared to baseline.

10.4 Executive Order 13045: Protection of Children from Environmental Health Risks and Safety Risks

Executive Order 13045 (62 FR 19885, April 23, 1997) applies to any rule that (1) is determined to be "economically significant" as defined under Executive Order 12866 and (2) concerns an environmental health or safety risk that the EPA has reason to believe might have a disproportionate effect on children. If the regulatory action meets both criteria, the Agency must evaluate the environmental health and safety effects of the planned rule on children and explain why the planned regulation is preferable to other potentially effective and reasonably feasible alternatives considered by the Agency.

As detailed in the Supplemental EA and BCA document (U.S. EPA, 2019c; 2019b), the EPA identified several ways in which the regulatory options would affect children, including by potentially increasing health risk from exposure to pollutants present in steam electric power plant discharges. The potential increases are estimated to be small and arise from less stringent limits or later deadlines for meeting effluent limits under certain regulatory options as compared to the baseline. The EPA quantified the changes in IQ losses from lead exposure among pre-school children and from mercury exposure *in-utero* resulting from maternal fish consumption under the four regulatory options, as compared to the baseline. The EPA also estimated changes in the number of children with very high blood lead concentrations (above 20 ug/dL) and IQs less than 70 may requiring compensatory education tailored to their specific needs.

The EPA estimated that the regulatory options could have a small impact on children. The analysis shows small potential changes in lead exposure (from fish consumption) for an average of 1.5 million children annually, and in mercury exposure (from maternal fish consumption) for an average of 203,000 infants born annually. However, the EPA estimates the resulting health impacts to be small. The EPA estimated that the regulatory options would lead to slight increases in lead and mercury exposure, increasing IQ losses by approximately four points from lead exposure and between 400 and 3,800 points from mercury exposure over the entire exposed population across all four options. The social welfare effects from increased IQ loss associated with children's exposure to lead and mercury range from -$0.4 million to -$3.3 million across all regulatory options, using a 3 percent discount rate. Chapter 5 in the BCA document provides further details (U.S. EPA, 2019b). An estimated 7.2 million children aged 0 to 18 years live in households served by drinking water systems that use source waters downstream of steam electric power plants. As detailed in Chapter 4 of the BCA document (U.S. EPA, 2019b), ELG regulatory options may affect the quality of public water supplies by changing pollutant loads to source waters. In particular, the EPA estimates that three of the four regulatory options may reduce children's exposure to trihalomethanes and other disinfection byproducts in drinking water and thus reduce their lifetime risk of developing bladder cancer. The EPA did not estimate children-specific risk since these adverse health effects generally follow long-term exposure.

The EPA did not quantify additional benefits to children from changes in exposure to steam electric pollutant discharges due to data limitations. These include changes in the incidence or severity of other health effects from exposure to lead, mercury, and other pollutants including arsenic, boron, cadmium, copper, nickel, selenium, thallium, and zinc.

10.5 Executive Order 13132: Federalism

Executive Order 13132 (64 FR 43255, August 10, 1999) requires the EPA to develop an accountable process to ensure "meaningful and timely input by State and local officials in the development of regulatory policies that have federalism implications." Policies that have federalism implications are defined in the Executive Order to include regulations that have "substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government."

Under section 6 of Executive Order 13132, the EPA may not issue a regulation that has federalism implications, that imposes substantial direct compliance costs, and that is not required by statute unless the federal government provides the funds necessary to pay the direct compliance costs incurred by State and local governments or unless the EPA consults with State and local officials early in the process of developing the regulation. The EPA also may not issue a regulation that has federalism implications and that preempts State law, unless the Agency consults with State and local officials early in the process of developing the regulation.

The EPA has concluded that this action would not have federalism implications. As discussed in earlier chapters of this document, the EPA anticipates that this proposed action would not impose a significant incremental administrative burden on States from issuing, reviewing, and overseeing compliance with discharge requirements. With respect to direct compliance costs, while the regulatory options may impose such costs on State or local governments that own steam electric power plants, and the Federal government would not provide the funds necessary to pay those costs, the regulatory options are estimated to provide savings to State or local governments when compared to the costs they would incur under the baseline.

Specifically, the EPA has identified 160 steam electric power plants that are owned by State or local government entities or other political subdivisions. The EPA estimates that the maximum compliance cost in any one year to governments (excluding federal government) ranges from $20.5 million under Option 1 to $38.1 million under Option 4 (see *Chapter 9: Unfunded Mandates Reform Act (UMRA)* for details). This is compared to a maximum compliance cost to governments of $44.1 million under the baseline. Annualized cost savings to governments range from $5.5 million under Option 4 to $24.9 million under Option 2.

10.6 Executive Order 13175: Consultation and Coordination with Indian Tribal Governments

Executive Order 13175 (65 FR 67249, November 6, 2000) requires the EPA to develop an accountable process to ensure "meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications." "Policies that have tribal implications" is defined in the Executive Order to include regulations that have "substantial direct effects on one or more Indian Tribes, on the relationship between the Federal government and the Indian Tribes, or on the distribution of power and responsibilities between the federal government and Indian Tribes."

The EPA assessed potential tribal implications for the regulatory options arising from three main changes, as described below: (1) direct compliance costs incurred by plants; (2) impacts on drinking water systems downstream from steam electric power plants; and (3) administrative burden on governments that implement the NPDES program.

- Direct compliance costs: The EPA's analyses show that no plant estimated to be affected by the regulatory options is owned by tribal governments.

- Impacts on drinking water systems: The EPA identified 15 public water systems operated by tribal governments that may be affected by bromide discharges from steam electric power plants.[57] These systems serve a total of 18,917 people. This analysis finds small changes in exposure between baseline and the evaluated options and therefore small changes in risk for this population. The analysis is detailed in Chapter 4 of the BCA (U.S. EPA, 2019b).

- Administrative burden: No tribal governments are currently authorized pursuant to section 402(b) of the CWA to implement the NPDES program.

10.7 Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

Executive Order 13211 requires Agencies to prepare a Statement of Energy Effects when undertaking certain agency actions. Such Statements of Energy Effects shall describe the effects of certain regulatory actions on energy supply, distribution, or use, notably: (i) any adverse effects on energy supply, distribution, or use (including a shortfall in supply, price increases, and increased use of foreign supplies) should the proposal be implemented, and (ii) reasonable alternatives to the action with adverse energy effects and the estimated effects of such alternatives on energy supply, distribution, and use.

The OMB implementation memorandum for Executive Order 13211 outlines specific criteria for assessing whether a regulation constitutes a "significant energy action" and would have a "significant adverse effect on the supply, distribution or use of energy."[58] Those criteria include:

- Reductions in crude oil supply in excess of 10,000 barrels per day;

- Reductions in fuel production in excess of 4,000 barrels per day;

- Reductions in coal production in excess of 5 million tons per year;

- Reductions in natural gas production in excess of 25 million mcf per year;

- Reductions in electricity production in excess of 1 billion kilowatt-hours per year, or in excess of 500 megawatts of installed capacity;

[57] The EPA included public water systems identified in the EPA's Safe Drinking Water Information System as having a tribe as the primacy agency and one tribe-operated system with the state of Oklahoma as the primacy agency.

[58] Executive Order 13211 was issued May 18, 2002. The OMB later released an Implementation Guidance memorandum on July 13, 2002.

- Increases in the cost of energy production in excess of 1 percent;
- Increases in the cost of energy distribution in excess of 1 percent;
- Significant increases in dependence on foreign supplies of energy; or
- Having other similar adverse outcomes, particularly unintended ones.

None of the criteria above regarding potential significant adverse effects on the supply, distribution, or use of energy (listed above) apply to the proposed rule. While the regulatory options might affect (1) the production of electricity, (2) the amount of installed capacity, (3) the cost of energy production, and (4) the dependence on foreign supplies of energy, the four options analyzed by the EPA provide cost savings when compared to the baseline, reducing electricity generation costs. As described below and demonstrated by the results from the national electricity market analyses conducted for two regulatory options (Options 2 and 4) (see *Chapter 5: Electricity Market Analyses*), changes for the first three factors are in a direction than does not present a concern under this Executive Order or are smaller than the thresholds of concern specified by OMB.

10.7.1 Impact on Electricity Generation

The electricity market analyses (*Chapter 5*) estimate that under Option 2 coal-fired generation, including generation from power plants to which the option applies, would increase by about 0.1 percent to 0.6 percent in 2030 through 2050, relative to baseline generation. Coal-fired generation under Option 4 would change from a decline of 0.2 percent to an increase of 0.3 percent during that same period, depending on the year. Under both options, the changes in coal-fired generation would be offset by roughly corresponding changes in production from other plants, resulting in no net decrease in overall production; electricity generated in 2030 increases by 95 GWh and 215 GWh respectively for Options 2 and 4 in 2030, which is less than 0.01 percent of baseline generation. These changes are very small, and consequently, the EPA does not believe that the proposed rule constitutes a “significant energy action” in terms of overall impact on electricity generation.

10.7.2 Impact on Electricity Generating Capacity

As documented in *Chapter 5*, the Agency’s electricity market analysis estimated that by 2030 Option 2 would result in net avoided retirement of 893 MW of generating capacity, whereas Option 4 would result in net avoided retirement of 724 MW of generating capacity.

10.7.3 Cost of Energy Production

Based on the IPM analysis results, the EPA estimated that the regulatory options would not significantly affect the total cost of electricity production. At the national level, total electricity generation costs (fuel, variable O&M, fixed O&M and capital) under Option 2 are projected to decrease by 0.1 percent, whereas production costs under Option 4 are essentially unchanged (less than 0.01 percent change). At the regional level, the change in electricity generation costs varies. Table 5-4 in Chapter *5* summarizes changes projected in IPM for the 2030 run year and shows range from a decrease of 0.3 percent in RFC under Option 2 to negligible increases (less than 0.1 percent) in several regions under either Option 2 or Option 4. None of the NERC regions show increases approaching 1 percent under either option.

Consequently, no region would experience energy price increases greater than the 1 percent threshold as a result of the regulatory options in either the short or the long run. Consequently, the EPA does not believe that the proposed rule constitutes a "significant energy action" in terms of estimated potential effects on the cost of energy production.

10.7.4 Dependence on Foreign Supply of Energy

The EPA's electricity market analyses did not support explicit consideration of the effects of the regulatory options on foreign imports of energy. However, the regulatory options directly affect electric power plants, which generally do not face significant foreign competition. Only Canada and Mexico are connected to the U.S. electricity grid, and transmission losses are substantial when electricity is transmitted over long distances. In addition, the effects on installed capacity and electricity prices are estimated to be small.

Table 10-1 presents IPM projected generating capacity and generation by type in 2030 under the baseline and for regulatory options 2 and 4. Under Option 2, coal-based electricity generation is projected to increase by 0.6 percent, while generation using several other sources of energy is estimated to either decrease (natural gas, biomass, solar) or increase (*i.e.*, oil/gas steam, landfill gas) depending on the type. Changes are less than 1 percent across all generation types.

Table 10-1: Total Market-Level Capacity and Generation by Type for Options 2 and 4 in 2030

	Generating Capacity (GW)					Electricity Generation (Thousand GWh)				
Type	**Base Case**	**Option 2**	**% Change**	**Option 4**	**% Change**	**Base Case**	**Option 2**	**% Change**	**Option 4**	**% Change**
Hydro	110.6	110.6	-0.03%	110.5	-0.08%	326.1	326.0	-0.05%	325.8	-0.11%
Biomass	0.4	0.4	0.00%	0.4	0.00%	2.1	2.1	-0.20%	2.1	-0.36%
Geothermal	3.0	3.0	0.00%	3.0	0.00%	21.2	21.2	0.00%	21.2	0.00%
Landfill Gas	1.9	1.9	0.00%	1.9	0.00%	9.9	9.9	0.02%	9.9	0.08%
Solar	110.8	110.6	-0.24%	110.8	-0.05%	202.3	201.9	-0.19%	202.2	-0.04%
Wind	149.9	149.8	-0.06%	149.9	0.01%	494.7	494.3	-0.08%	494.8	0.01%
Coal	169.9	171.0	0.65%	170.6	0.41%	882.2	887.1	0.56%	883.6	0.16%
Nuclear	76.6	76.5	-0.11%	76.7	0.10%	604.0	603.3	-0.12%	604.7	0.11%
Natural Gas	425.8	425.3	-0.12%	425.4	-0.11%	1,656.4	1,653.1	-0.20%	1,654.6	-0.11%
Oil/Gas Steam	71.7	71.5	-0.22%	71.6	-0.08%	56.9	57.0	0.10%	57.1	0.37%
Others	12.5	12.5	0.00%	12.5	0.00%	37.0	37.0	0.09%	37.0	0.08%
Total[a]	**1,133.3**	**1,133.2**	**0.00%**	**1,133.4**	**0.01%**	**4,292.8**	**4,292.8**	**0.00%**	**4,293.0**	**0.01%**

a. Numbers may not add up due to rounding.

Source: U.S. EPA Analysis, 2019.

Table 10-2 presents the corresponding projections of the quantity of fuel used for power generation. Changes are consistent with changes in generation presented in Table 10-1 with greater coal consumed (0.5 percent and 0.1 percent for Options 2 and 4, respectively) and less natural gas (0.2 percent and 0.1 percent for Options 2 and 4, respectively). Changes are generally less than 1 percent, with the exception of bituminous coal consumption which increases by 1.1 percent under Option 2.

Table 10-2: Total Market-Level Fuel Use by Fuel Type for Options 2 and 4 in 2030

	Fuel Consumption				
Fuel Type	**Baseline**	**Option 2**	**% Change**	**Option 4**	**% Change**
Coal (million tons)	484	486	0.50%	484	0.14%
Bituminous Coal (million tons)	151	153	1.14%	152	0.54%
Subbituminous Coal (million tons)	280	280	0.25%	280	-0.05%
Lignite (million tons)	53	53	-0.05%	53	0.01%
Natural Gas (trillion cubic feet)	12	12	-0.17%	12	-0.07%

Source: U.S. EPA Analysis, 2019.

Given the very small changes in coal and other fuels use under the two options, it is reasonable to assume that any increase in demand for fuel used in electricity generation would be met through domestic supply, thereby not increasing U.S. dependence on foreign supply of energy. Consequently, the EPA does not believe that the proposed rule constitutes a "significant energy action" from the perspective of energy independence.

10.7.5 Overall E.O. 13211 Finding

From these analyses and the electricity markets analysis in *Chapter 5*, the EPA concludes that the regulatory options would not have a *significant adverse effect* at a national or regional level under Executive Order 13211. Specifically, the Agency's analysis found that the regulatory options would not reduce electricity production in excess of 1 billion kilowatt hours per year or in excess of 500 megawatts of installed capacity under either of the options analyzed, nor would the option increase U.S. dependence on foreign supply of energy. As such, the proposed ELG does not constitute a significant regulatory action under Executive Order 13211 and the EPA did not prepare a Statement of Energy Effects.

10.8 Paperwork Reduction Act of 1995

The Paperwork Reduction Act of 1995 (PRA) (superseding the PRA of 1980) is implemented by OMB and requires that agencies submit a supporting statement to OMB for any information collection that solicits the same data from more than nine parties. The PRA seeks to ensure that Federal agencies balance their need to collect information with the paperwork burden imposed on the public by the collection.

The definition of "information collection" includes activities required by regulations, such as permit development, monitoring, record keeping, and reporting. The term "burden" refers to the "time, effort, or financial resources" the public expends to provide information to or for a Federal agency, or to otherwise fulfill statutory or regulatory requirements. PRA paperwork burden is measured in terms of annual time and financial resources the public devotes to meet one-time and recurring information requests (44 U.S.C. 3502(2); 5 C.F.R. 1320.3(b)). Information collection activities may include:

- reviewing instructions;
- using technology to collect, process, and disclose information;
- adjusting existing practices to comply with requirements;
- searching data sources;

- completing and reviewing the response; and
- transmitting or disclosing information.

Agencies must provide information to OMB on the parties affected, the annual reporting burden, the annualized cost of responding to the information collection, and whether the request significantly impacts a substantial number of small entities. An agency may not conduct or sponsor, and a person is not required to respond to, an information collection unless it displays a currently valid OMB control number.

OMB has previously approved the information collection requirements contained in the existing regulations 40 CFR part 423 under the provisions of the Paperwork Reduction Act.[59]

The regulatory options would not result in any significant change in the information collection requirements associated with initial permit application, re-permitting activities, and activities associated with monitoring and reporting after the permit is issued beyond those already required under the existing NPDES program.

The EPA estimated small changes in monitoring costs due to changes in the number of pollutants for which the EPA is proposing limits and standards, as well as monitoring of flow under the high recycle rate systems for bottom ash; the Agency accounted for these costs as part of its analysis of the economic impacts of the regulatory options (see *Chapter 3: Compliance Costs*). In some cases, in lieu of these monitoring requirements, steam electric power plants would have additional paperwork burden such as that associated with certifications and applicable BMP plans. However, plants would also realize savings, relative to the baseline, by no longer monitoring pollutants for some subcategories (and because their requirements are based on less costly technologies). The EPA projects that the burden associated with the new proposed paperwork requirements would be largely offset by the reduced burden associated with less monitoring; therefore, it projects that the proposal would have no net effect on the burden in the approved information collection requirements.

With respect to permitting authorities, based on the information in its record, the EPA also does not expect any of the regulatory options to increase or decrease their burden. The regulatory options would not change permit application requirements or the associated review; they would not affect the number of permits issued to steam electric power plants; nor would it change the efforts involved in developing or reviewing such permits. Accordingly, the EPA estimated no net change (increase or decrease) in the cost burden to federal or state governments or dischargers associated with any of the regulatory options in this proposed rule.

10.9 National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act (NTTAA) of 1995, Pub L. No. 104-113, Sec. 12(d) directs EPA to use voluntary consensus standards in its regulatory activities unless doing so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (*e.g.*, materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by voluntary consensus standard bodies. The NTTAA

[59] OMB has assigned control number 2040-0281 to the information collection requirements under 40 CFR part 423.

directs the EPA to provide Congress, through the OMB, explanations when the Agency decides not to use available and applicable voluntary consensus standards.

The regulatory options do not involve technical standards, for example in the measurement of pollutant loads. Nothing in the regulatory options would prevent the use of voluntary consensus standards for such measurement where available, and the EPA encourages permitting authorities and regulated entities to do so. Therefore, the EPA is not considering the use of any voluntary consensus standards.

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A Summary of Changes to Costs and Economic Impact Analysis

Table A-1 summarizes the principal methodological changes the EPA made to analyses of the costs and economic impacts of the proposed ELG reconsideration rule as compared to analysis of the 2015 rule described in the 2015 RIA document (U.S. EPA, 2015b).

Table A-1: Changes to Costs and Economic Impacts Analysis Since Proposal

Cost or Impact Category	Analysis Component	Cost or Impact Category
General assumptions	Dollar year [all costs expressed in 2013 dollars]	Updated dollar year [2018]
	Promulgation year [all costs and revenue streams discounted back to 2015]	Updated promulgation year [2020]
	Period of analysis [2019-2042]	Updated period of analysis [2021-2047]
	Technology implementation years [2019-2023]	
	Technology implementation years constant across the options for a given plant	Updated technology implementation years [2021-2028]
General inputs for screening-level analyses	Generation, plant revenue, and estimated electricity prices using EIA-861 and EIA-923 databases; six-year (2007-2012) average values	Updated with data from more current EIA-861 and EIA-923 databases to use more recent six-year [2011-2016] average values
	Generating capacity from 2012 EIA-860	Updated using 2016 EIA-860
	Electricity revenue, sales, and number of consumers by consumer class (residential, industrial, commercial, and transportation) for ASCC and HICC regions from EIA-861 for [2012]	Updated to use data from EIA-861 for [2016]
	Electricity revenue, sales, and number of consumers by consumer class (residential, industrial, commercial, and transportation) for NERC regions other than ASCC and HICC regions from [2013] AEO projections	Updated using [2018] AEO projections
Industry profile	Total count of plants (1,080 plants)	Updated universe of 951 plants reflects information on actual, planned, and announced unit retirements through the end of 2028.
	Industry data (*i.e.*, capacity, generation, number of plants, etc.) from 2012 EIA databases	Updated using 2016 EIA databases
Screening-level plant impacts	Cost-to-revenue impact indicators (1% and 3%) based on 6-year (2007-2012) average values of electricity generation and electricity prices (to estimate plant-level revenue)	Updated to use average electricity generation and electricity prices for [2011-2016]
Market-level impacts (IPM)	IPM platform [v 5.13] which reflects demand projections and other model assumptions based on 2013 Annual Energy Outlook.	IPM v.6 based on AEO 2018

Table A-1: Changes to Costs and Economic Impacts Analysis Since Proposal		
Cost or Impact Category	**Analysis Component**	**Cost or Impact Category**
	Existing regulations include proposed CPP rule.	Existing regulations exclude CPP rule.
	NEEDS V5.13 database	NEEDS v6 database
Impacts on employment	Estimate of total labor hours needed to install the compliance technology or for O&M	Discuss qualitatively (direction and relative magnitude of potential changes), following the general approach used in the CPP repeal RIA
	Impacts to wastewater treatment system suppliers discussed qualitatively	
	Impacts to virgin material based on labor intensity	
	Impacts to coal mining and natural gas extraction sectors (as FTE) based on labor productivity	
Potential electricity price effects	Simple assumption of 100 percent compliance cost passthrough	No change
	Projected total electricity sales in [2015] from [AEO 2013]	Projected total electricity sales in [2020] from [AEO 2018]
	Electricity sales data by consumer group from [2012] EIA-860 database	Electricity sales data by consumer group from [2016] EIA-860 database
	Evaluated differential impacts on households by income level (*i.e.*, distributional analysis)	Did not update this analysis: Cost savings make differential burden on households with different income levels less relevant
Owner-level impacts and RFA/SBREFA	Owners identified in Steam Electric Survey	Owners identified in EIA-860 [2016]
	Revenue from Steam Electric Survey	Revenue from Annual Reports and other publicly available sources (*e.g.*, company websites), or estimated based on EIA electricity sales data if unavailable
	Small business size determination metrics [mostly industry survey for private entities; Census 2013 for governments]	Small business size determination metrics [mostly publicly available sources for private entities; Census ACS 2016 for governments]
UMRA Analysis	Use the social cost framework to get expenditures on a year-explicit basis for each plant, by owner type	No change
EO 12866: Cost-benefits	Refer to BCA Chapter 12	No change
EO 12898: EJ	Refers to BCA Chapter 14. Qualitative discussion draws on benefits analyses. See Table 2 for details. Presents profile of population in the vicinity of steam electric power plants and selected results of the benefits analyses by income and minority status	Update profile and discussion of distributional effects to reflect exposure via drinking water
EO 13045: Children's health	Qualitative discussion draws on benefits analysis. See Table 2 for details.	No change
EO 13132: Federalism	Qualitative discussion draws on compliance cost results	No change

B Comparison of Incremental Costs and Pollutant Removals

This appendix describes the EPA's analysis of the incremental costs and pollutant removals of the regulatory options. The information provides insight into how regulatory options compare to each other in terms of reducing toxic pollutant discharges to surface waters.

B.1 Methodology

Cost-effectiveness is defined as the incremental annualized cost of a pollution control option in an industry or industry subcategory per incremental pound equivalent of pollutant (*i.e.*, pound of pollutant adjusted for toxicity) removed by that control option. The analysis compares removals for pollutants directly regulated by the ELGs and incidentally removed along with regulated pollutants.

As described for the 2015 rule, the EPA's cost-effectiveness analysis involves the following steps to generate input data and calculate the desired values (see Appendix F in U.S. EPA, 2015b):

1. Determine the pollutants considered for regulation.
2. For each pollutant, obtain relative toxic weights and POTW removal factors.
3. Define the regulatory pollution control options.
4. Calculate pollutant removals and toxic-weighted pollutant removals for each control option and for each of direct and indirect discharges. For indirect dischargers, the calculations include applying a factor that reflects the ability of a POTW or sewage treatment plant to remove pollutants prior to discharge to water. See *Supplemental TDD* (2019a) for details.
5. Determine the total annualized compliance cost for each control option and for direct and indirect dischargers.
6. Adjust the cost obtained in step 5 to 1981 dollars.
7. Calculate the cost-effectiveness ratios for each control option and for direct and indirect dischargers.

The four regulatory options represent only a subset of the requirements contained in the ELG for the steam electric industry since they address only two of the relevant wastestreams. Accordingly, the EPA did not calculate the cost-effectiveness ratios for the four regulatory options since these ratios would not be comparable to cost-effectiveness values the EPA estimated for the 2015 rule (see Appendix F in U.S. EPA, 2015b) or for ELGs for other point source categories. The next section provides results for steps 1 through 5, where the total annualized compliance costs calculated in step 5 are relative to the 2015 rule baseline.[60]

[60] Adjustment of costs to 1981 dollars is a convention to facilitate comparison of cost-effectiveness values across rules. Since the EPA is not estimating cost-effectiveness ratios in this analysis, this adjustment was not needed.

B.2 Results

Toxic Weights of Pollutants and POTW Removal

The *Supplemental TDD* provides information on the pollutants addressed by the regulatory options (U.S. EPA, 2019a). The pollutants include several metals (*e.g.*, arsenic, mercury, selenium), various non-metal compounds (*e.g.*, chloride, fluoride, sulfate), nutrients, and conventional pollutants (*e.g.*, oil and grease, biochemical oxygen demand.)

The toxic weighted pound equivalent (TWPE) analysis involves multiplying the changes in loadings of each pollutant by a pollutant-specific toxic weighting factor (TWF) that represents the toxic effect level relative to the toxicity of copper. For indirect dischargers, the changes are multiplied by a second factor that reflects the ability of a POTW or sewage treatment plant to remove pollutants prior to discharge to waters. For TWF and POTW removal factors, see Appendix F in U.S. EPA (2015b).

Evaluated Options

The EPA analyzed four options summarized in Table 1-1.

Pollutant Removals and Pound Equivalent Calculations

Table B-1, below, presents estimated annual reduction in the mass loading of pollutant anticipated from direct and indirect dischargers for each regulatory option, relative to the baseline. The toxic weighted removals account for pollutant toxicity and, for indirect dischargers, for POTW removals. The calculations do not account for the removal of pollutants that do not have TWFs, either because data are not available to set a TWF or toxicity is not the pollutant's primary environmental impact (*e.g.*, nutrients contributing to eutrophication, high BOD resulting in anoxia). Furthermore, the pound equivalent pollutant removal analysis does not address routes of potential environmental damage and human exposure, and therefore potential benefits from reducing pollutant exposure.

Annualized Compliance Costs

The EPA developed costs for technology controls to address each of the wastestreams present at each steam electric power plant. The *Supplemental TDD* provides additional details on the methods used to estimate the costs of meeting the limitations and standards under the baseline and each of the regulatory options (U.S. EPA, 2019a). The method used to calculate the incremental annualized compliance costs is described in greater detail in *Chapter 3: Compliance Costs*. The EPA categorized these annualized compliance costs as either direct or indirect based on the discharge associated with each wastestream at each plant.[61] Table B-1 summarizes the annualized compliance costs of the four regulatory options relative to the 2015 rule baseline, whereas Figure B-1 compares the pollutant removals and costs of the four regulatory options graphically.

[61] One plant has one of its wastestreams identified as discharged both directly and indirectly. For this plant and wastestream, the EPA allocated compliance costs equally to the direct and indirect categories.

Table B-1: Estimated Pollutant Removal and Costs of Regulatory Options by Discharger Category

Discharger Category	Option[a]	Total Annual TWF-Weighted Pollutant Removals (lb-eq.)		Total Annual Pre-tax Compliance Costs (million, 2018$)	
		Total[b]	Incremental[c]	Total[b]	Incremental[c]
Direct	1	-87,291	-87,291	-$163.1	-$163.1
	2	13,719	101,010	-$170.2	-$7.1
	3	69,550	55,831	-$125.0	$45.2
	4	394,012	324,462	-$25.0	$100.0
Indirect	1	-526	-526	-$2.5	-$2.5
	3	68	594	-$5.5	-$2.9
	2	-646	-714	-$1.4	$4.1
	4	4,574	5,220	-$0.5	$0.9

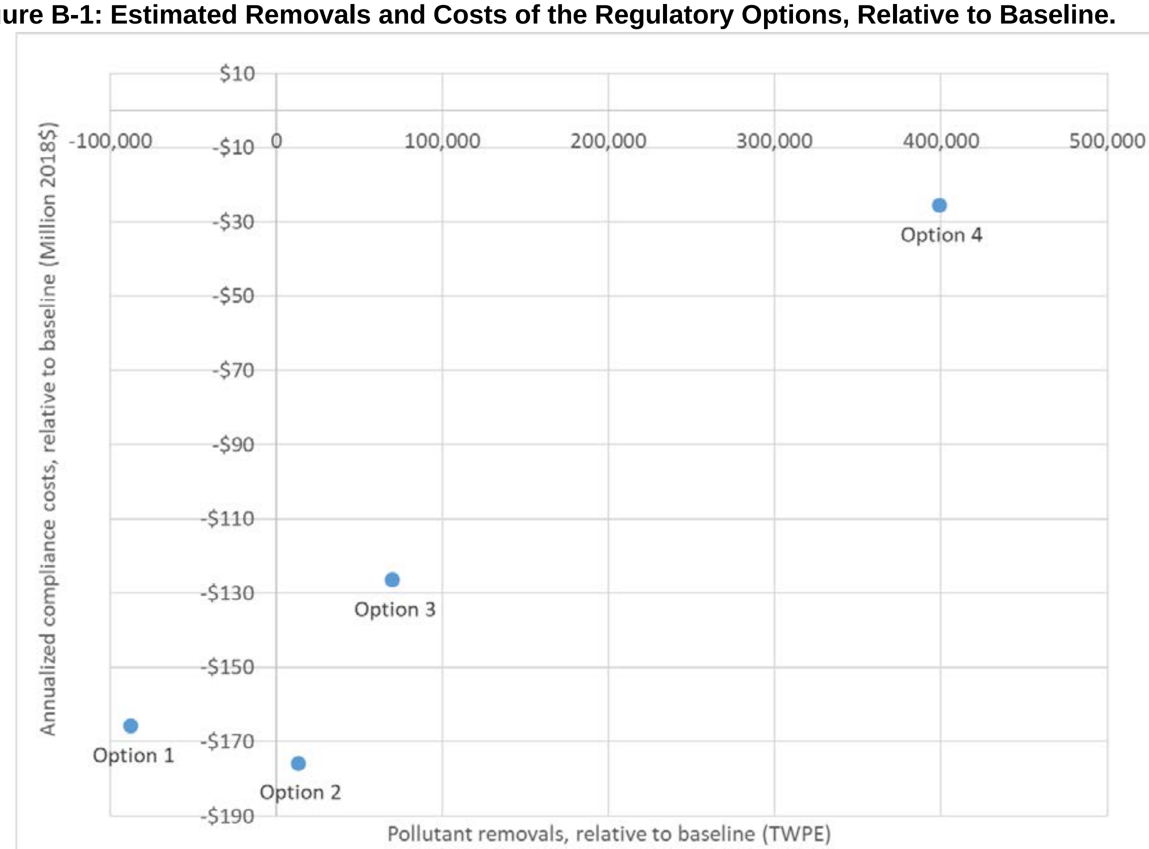
a. Options are listed in increasing order of pollutant removals, relative to the baseline.

b. Total removals and costs are compared to those for the baseline.

c. Incremental removals and costs are compared to those for the next least stringent option in the order listed in the table. For direct dischargers, the incremental removals and costs under Option 1 are calculated relative to the baseline, the incremental removals and costs for Option 2 are calculated relative to those of Option 1, etc.

Source: U.S. EPA Analysis, 2019

Figure B-1: Estimated Removals and Costs of the Regulatory Options, Relative to Baseline.



C IPM Sensitivity Analysis Including ACE Rule

EPA promulgated the Affordable Clean Energy (ACE) final rule on June 19, 2019 (84 FR 32520). The rule provides emission guidelines for greenhouse gas (GHG) emissions from existing electric utility generating units (EGUs) under section 111(d) of the Clean Air Act. The guidelines inform states in the development, submittal, and implementation of state plans that establish standards of performance for CO_2 from certain existing coal-fired EGUs within their jurisdictions. To analyze the regulatory impacts of the ACE final rule, the Agency developed an illustrative policy scenario that models adoption of heat rate improvement (HRI) measures at coal-fired EGUs and used this scenario to assess the emissions, compliance costs, and other energy-sector effects of the ACE final rule.

The analysis of the proposed ELG options discussed in Chapter 5 was completed before the Agency finalized the ACE rule, and therefore does not include the projected effects of the ACE rule. This appendix complements the analysis detailed in Chapter 5 by providing information about the projected impacts of the proposed ELG in the context of an electricity market that includes the effects of the ACE final rule. Specifically, the EPA conducted a sensitivity analysis that uses the ACE illustrative scenario as the basis against which to evaluate the impacts of proposed Option 2. In this appendix, we refer to the ACE illustrative scenario as the "alternative baseline." The EPA used existing IPM results, that include the ACE final rule, for this alternative baseline and ran an additional scenario that adds proposed Option 2 to this baseline for the purpose of determining the effect of proposed Option 2.

In the following sections, we first summarize differences between the baseline used for analyses presented in Chapter 5 and the alternative baseline that includes the ACE final rule (Section C.1). We then summarize the market-level impacts of proposed Option 2 (Section C.2). The market-level impacts are addressed in two sets of analyses that parallel the analyses described in Chapter 5:

- *Analysis of national-level impacts*: The EPA analyzed IPM results reported for a series of run years to provide insight on the direction and magnitude of market-level changes attributable to the ELG option over time.
- *Analysis of long-term regulatory impacts*: The EPA analyzed IPM results for run year 2030 to provide insight on post-compliance conditions for the entire electricity market and for steam electric power plants specifically.

Overall, the sensitivity analysis with the ACE final rule shows impacts that are very similar to those presented in Chapter 5 for the scenarios without the ACE final rule. The sensitivity analysis shows a slightly greater reduction in steam electric capacity retirement resulting from proposed Option 2 than the primary analysis, even though it also shows one net full-plant retirement versus no net full-plant retirement for the primary analysis (see details in

Impacts on Steam Electric Power Plants as a Group below).

C.1 Baseline Changes

Table C-1 summarizes the baseline used for the proposed rule and the alternative baseline IPM projections of total costs to electric power plants, wholesale electricity price, total existing capacity, new capacity, plant retirements, and generation mix at the national level. These baseline projections show a progressive decline in total coal and nuclear generation capacities, and increases in generation capacity from renewables, natural gas, and other sources. Changes over time are smaller in the alternative baseline; the coal generation capacity declines by 13.5 GW (8 percent) between 2021 and 2040, as compared to a 31.9 GW (18 percent) decline for the baseline without the ACE final rule. Neither baseline shows coal capacity additions during the period.

Table C-1: Baseline Projections Without and With ACE Final Rule

Economic Measures	Baseline (Without ACE)					Alternative Baseline (With ACE)				
	2021	2025	2030	2040	2050	2021	2025	2030	2040	2050
Total Costs										
Total Costs (million 2018$)	$135,820	$145,980	$156,921	$179,174	$188,890	$135,781	$146,263	$157,189	$164,725	$178,811
Prices										
National Wholesale Electricity Price (mills/kWh)	33.40	39.22	42.96	44.79	45.28	33.45	39.15	42.93	43.08	44.66
Total Capacity (Cumulative GW)										
Renewables[a]	290.3	321.1	376.8	383.3	435.2	290.3	322.3	377.1	382.0	383.4
Coal	176.4	171.8	169.9	161.5	144.5	174.3	169.7	167.9	163.4	160.9
Nuclear	88.4	81.3	76.6	75.4	73.3	88.4	81.3	76.7	75.5	75.5
Natural Gas	407.7	415.5	425.8	509.6	622.0	407.9	416.4	427.2	464.8	509.8
Oil/Gas Steam	71.3	71.7	71.7	71.3	67.2	71.7	72.1	72.1	72.0	71.6
Other	9.6	11.1	12.5	12.5	12.8	6.4	6.4	6.4	6.4	6.4
Grand Total	1,043.7	1,072.6	1,133.3	1,213.7	1,355.1	1,042.2	1,072.9	1,133.4	1,170.2	1,213.7
New Capacity (Cumulative GW)										
Renewables[a]	66.8	97.7	153.4	159.9	211.8	66.8	98.9	153.7	158.6	160.1
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Natural Gas	2.2	10.1	20.7	104.5	217.0	2.4	10.9	22.1	59.7	104.7
Other	2.5	4.0	5.4	5.4	5.7	0.0	0.0	0.0	0.0	0.0
Grand Total	71.6	111.9	179.5	269.8	434.5	71.7	113.8	181.2	223.7	270.2
Retirements (GW)[b]										
Combined Cycle	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
Coal	48.3	49.3	51.0	59.4	75.8	50.4	51.4	53.0	57.5	60.1
Combustion Turbine	1.6	1.6	1.9	1.9	1.9	1.6	1.6	1.9	1.9	1.9
Nuclear	3.9	12.2	17.0	18.1	20.2	3.9	12.2	16.9	18.0	18.0
Oil/Gas	6.0	5.9	6.0	6.3	10.5	5.6	5.6	5.6	5.6	6.1
Grand Total	67.0	76.4	83.2	93.1	116.3	68.6	78.1	84.7	90.4	93.4

Table C-1: Baseline Projections Without and With ACE Final Rule

Economic Measures	Baseline (Without ACE)					Alternative Baseline (With ACE)				
	2021	2025	2030	2040	2050	2021	2025	2030	2040	2050
Generation Mix (thousand GWh)										
Renewables[a]	842.6	906.6	1,056.3	1,076.2	1,252.8	842.5	908.0	1,056.0	1,069.3	1,075.3
Coal	867.1	919.1	882.2	790.4	716.5	867.2	921.5	884.2	784.9	796.6
Nuclear	694.3	642.7	604.0	596.6	579.4	694.3	642.7	604.8	597.3	597.3
Natural Gas	1,576.1	1,613.8	1,656.4	2,026.8	2,303.3	1,576.1	1,610.7	1,655.0	1,865.1	2,020.6
Oil/Gas Steam	62.9	60.8	56.9	43.9	15.7	62.8	59.9	56.1	61.0	44.3
Other	35.3	36.3	37.0	37.5	37.6	32.0	32.0	31.4	31.4	31.4
Grand Total	4,078.4	4,179.2	4,292.8	4,571.3	4,905.2	4,078.3	4,179.0	4,293.2	4,414.8	4,571.6

a. Renewables include hydropower and non-hydropower renewables.

b. There were no changes in projected retirements for IGCC, biomass, fuel cell, other fossil fuel, geothermal, hydropower, landfill gas, other non-fossil fuel, and energy storage plants.

Source: U.S. EPA Analysis, 2019

C.2 Market Level Impacts

Summary of Impacts Over Analysis Period

The EPA compared the baseline and policy case (with proposed Option 2) IPM results reported for a series of run years[62] to provide insight on the direction and magnitude of market-level changes attributable to the proposed ELG option over time. Table C-2 provides incremental changes in these measures for Option 2, relative to the baseline presented in Chapter 5 and relative to the alternative baseline (negative values represent decreases relative to the baseline). The changes attributable to Option 2 are generally small under both baseline scenarios. For most economic measures and years analyzed, the incremental impacts of Option 2 are larger when evaluated against the alternative baseline, but they remain small relative to values summarized in Table C-1.

Table C-2: National Impact of Proposed Regulatory Option (Option 2) Relative to Baseline and Alternative Baseline

Economic Measures	Option 2 Changes Relative to Baseline					Option 2 Changes Relative to Alternative Baseline				
	2021	2025	2030	2040	2050	2021	2025	2030	2040	2050
Total Costs										
Total Costs (million 2018$)	-$193.5	-$186.7	-$140.1	-$53.3	$13.6	-$219.9	-$182.4	-$125.7	-$93.1	-$17.5

62 For conciseness, the tables show results for the years 2021, 2025, 2030, 2040, and 2050, but IPM V6 also provides projections for model years 2023, 2035, and 2045.

Table C-2: National Impact of Proposed Regulatory Option (Option 2) Relative to Baseline and Alternative Baseline

Economic Measures	Option 2 Changes Relative to Baseline					Option 2 Changes Relative to Alternative Baseline				
	2021	2025	2030	2040	2050	2021	2025	2030	2040	2050
Prices										
National Wholesale Electricity Price (mills/kWh)	-0.08	-0.02	-0.05	-0.01	0.01	-0.09	-0.01	-0.02	0.01	0.01
Total Capacity (Cumulative GW)										
Renewables[a]	0.0	-1.1	-0.4	-0.3	-0.4	0.0	-1.3	-0.1	0.0	-0.1
Coal	**1.2**	**1.2**	**1.1**	**0.7**	**0.8**	**1.3**	**1.3**	**1.2**	**1.1**	**0.9**
Nuclear	0.0	0.0	-0.1	-0.1	-0.1	0.0	0.0	-0.3	-0.3	-0.3
Natural Gas	0.0	0.1	-0.5	-0.3	-0.5	0.0	0.0	-0.7	-0.7	-0.4
Oil/Gas Steam	-0.2	-0.2	-0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Grand Total	1.1	0.0	0.0	-0.1	-0.2	1.3	0.0	0.0	0.0	-0.1
New Capacity (Cumulative GW)										
Renewables[a]	0.0	-1.1	-0.4	-0.3	-0.4	0.0	-1.3	-0.1	0.0	-0.1
Coal	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Natural Gas	0.0	0.1	-0.6	-0.3	-0.5	0.0	0.0	-0.8	-0.7	-0.5
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Grand Total	0.0	-1.1	-0.9	-0.7	-0.9	0.0	-1.3	-0.9	-0.8	-0.6
Retirements (GW)[b]										
Combined Cycle	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	**-1.2**	**-1.2**	**-1.1**	**-0.7**	**-0.8**	**-1.3**	**-1.3**	**-1.2**	**-1.1**	**-0.9**
Combustion Turbine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	0.0	0.0	0.1	0.1	0.1	0.0	0.0	0.3	0.3	0.3
Oil/Gas	0.2	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Grand Total	-1.1	-1.1	-0.9	-0.6	-0.7	-1.3	-1.3	-0.9	-0.8	-0.5
Generation Mix (thousand GWh)										
Renewables[a]	-0.1	-1.8	-0.9	-0.8	-0.5	0.0	-1.9	-0.5	-0.6	-0.6
Coal	**1.6**	**2.2**	**4.9**	**1.8**	**0.9**	**0.2**	**4.2**	**6.3**	**5.2**	**3.5**
Nuclear	0.0	0.0	-0.7	-0.7	-0.7	0.0	0.0	-2.8	-2.8	-2.8
Natural Gas	-1.1	-0.1	-3.3	0.0	0.4	0.0	-2.2	-3.2	-1.8	-0.5
Oil/Gas Steam	-0.2	-0.3	0.1	0.0	0.1	0.0	0.1	0.4	-0.2	0.4
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Grand Total	0.2	0.1	0.1	0.3	0.1	0.3	0.2	0.1	-0.1	0.1

a. Renewables include hydropower and non-hydropower renewables.

b. There were no changes in projected retirements for IGCC, biomass, fuel cell, other fossil fuel, geothermal, hydropower, landfill gas, other non-fossil fuel, and energy storage plants.

Source: U.S. EPA Analysis, 2019

Detailed Market-level Impacts for Year 2030

This analysis looks at conditions in the period of 2028 through 2033, when plants are estimated to meet the revised BAT limits and pretreatment standards associated with each analyzed regulatory option. Following the approach described in Section 5.2.2, the EPA used parsed IPM outputs and considered impact metrics of interest at three levels of aggregation discussed below: (1) national and regional electricity markets; (2) steam electric power plants as a group; and (3) individual steam electric power plants.

Impacts on National and Regional Electricity Markets in 2030

Following the approach described in Chapter 5, EPA compared market-level outputs for the year 2030 relative to the alternative baseline. Table C-3 presents results at the level of the national market and for regional electricity markets defined on the basis of NERC regions. For comparison purposes, the table includes the results previously obtained for Option 2 relative to the baseline without ACE (as presented in Table 5-4).

The impacts of the proposed Option 2 relative to the alternative baseline are very similar to those discussed in Chapter 5 for the baseline that does not include ACE: Option 2 has small effects on the electricity market relative to the baseline, on both a national and regional sub-market basis, in the year 2030.

At the national level, total annual costs decrease by an estimated $126 million (approximately 0.1 percent) relative to the alternative baseline. The results show a similar distribution of impacts across regions with the RFC region having the largest decline in total costs, $155 million (0.4 percent), followed by the SPP region with decreases of $16 million (0.2 percent). Whereas Option 2 resulted in cost savings for the SERC region when compared to the baseline without ACE, the sensitivity analysis shows a small *increase* in total costs for this region of $47 million (0.1 percent) relative to the alternative baseline.

Overall at the national level, the net change in total capacity, including increases in existing capacity (which includes avoided early retirements) and reductions in new plants/units, is an increase of approximately 2.4 GW in capacity, which is about 0.2 percent of total market capacity. Although effects differ across the regions, Option 2 is estimated to have minimal effect on capacity availability and supply reliability at the national level. The net capacity increase is primarily a result of a gain in capacity in the SERC region of about 2.5 GW (0.9 percent of SERC region capacity) due to a combination of avoided early retirements and reduced new capacity additions. Other regions projected to experience gains in capacity are NPCC and SPP. IPM projects net losses in capacity in the RFC region of 0.4 GW (0.2 percent), as well as smaller losses in FRCC.

Similar to results presented in Chapter 5, overall impacts on wholesale electricity prices are small. Wholesale electricity prices are estimated to increase in some NERC regions and fall in others. Price changes in individual regions range from -$0.11 per MWh (-0.3 percent) in SERC to $0.12 per MWh (0.3 percent) in NPCC.

At the national level, the sensitivity analysis shows increases in emissions for all air pollutants modeled, as was the case for the baseline without ACE. These increases are greater than those predicted relative to the baseline without ACE. NOx emissions increase by 0.6 percent; SO_2 emissions increase by 0.6 percent;

CO_2 emissions increase by 0.4 percent, mercury emissions increase by 0.5 percent; and HCL emissions increase by 0.7 percent. The impact on emissions varies across regions and by pollutant.

Table C-3: Impact of Proposed ELG Option 2 on National and Regional Markets at the Year 2030, Relative to Baseline and Alternative Baseline

Economic Measures (all dollar values in 2018$)	Baseline	Option 2 without ACE			Alternative Baseline	Option 2 with ACE		
		Value	Diff.	% Change		Value	Diff.	% Change
National Totals								
Total Domestic Capacity (GW)	1,142.5	1,143.1	0.6	0.1%	1,143.0	1,145.4	2.4	0.2%
Existing			1.5	0.1%			3.2	0.3%
New Additions			-0.9	-0.1%			-0.9	-0.1%
Early Retirements			-1.5	-0.1%			-3.2	-0.3%
Wholesale Price ($/MWh)	$42.96	$42.90	-$0.05	-0.1%	$42.93	$42.91	-$0.02	0.0%
Generation (TWh)	4,286	4,287	0.1	0.0%	4,287	4,287	0.1	0.0%
Costs ($Millions)	$156,921	$156,781	-$140	-0.1%	$157,189	$157,064	-$126	-0.1%
Fuel Cost	$69,971	$70,028	$57	0.1%	$69,634	$69,763	$129	0.2%
Variable O&M	$10,261	$10,263	$2	0.0%	$10,276	$10,289	$13	0.1%
Fixed O&M	$52,916	$52,834	-$82	-0.2%	$53,334	$53,200	-$134	-0.3%
Capital Cost	$23,774	$23,657	-$117	-0.5%	$23,945	$23,812	-$134	-0.6%
Variable Production Cost ($/MWh)	$18.72	$18.73	$0.01	0.1%	$18.64	$18.67	$0.03	0.2%
CO2 Emissions (Million Metric Tons)	1,581.1	1,585.1	3.9	0.2%	1,570.9	1,576.5	5.7	0.4%
Mercury Emissions (Tons)	4.45	4.47	0.02	0.4%	4.43	4.45	0.02	0.5%
NOx Emissions (Million Tons)	0.810	0.814	0.004	0.5%	0.80	0.81	0.005	0.6%
SO2 Emissions (Million Tons)	0.886	0.891	0.006	0.6%	0.88	0.88	0.005	0.6%
HCL Emissions (Million Tons)	0.004	0.005	0.000	0.5%	0.00	0.00	0.000	0.7%
Florida Reliability Coordinating Council (FRCC)								
Total Domestic Capacity (GW)	59.5	59.5	0.0	0.0%	59.4	59.4	0.0	-0.1%
Existing			0.0	0.0%			0.0	0.0%
New Additions			0.0	0.0%			0.0	-0.1%
Early Retirements			0.0	0.0%			0.0	0.0%
Wholesale Price ($/MWh)	$46.41	$46.41	$0.00	0.0%	$46.31	$46.31	$0.00	0.0%
Generation (TWh)	256	256	-0.1	0.0%	256	256	0	0.0%
Costs ($Millions)	$10,411	$10,404	-$7	-0.1%	$10,414	$10,409	-$5	0.0%
Fuel Cost	$6,662	$6,661	-$1	0.0%	$6,647	$6,650	$3	0.0%
Variable O&M	$605	$605	$0	0.1%	$608	$610	$1	0.2%
Fixed O&M	$2,643	$2,638	-$4	-0.2%	$2,661	$2,656	-$5	-0.2%
Capital Cost	$502	$499	-$3	-0.6%	$498	$493	-$4	-0.9%
Variable Production Cost ($/MWh)	$28.39	$28.40	$0.01	0.0%	$28.37	$28.39	$0.02	0.1%
CO2 Emissions (Million Metric Tons)	97.0	96.9	-0.1	-0.1%	97.2	97.3	0.0	0.0%
Mercury Emissions (Tons)	0.22	0.22	0.00	-0.1%	0.22	0.22	0.00	0.0%

Table C-3: Impact of Proposed ELG Option 2 on National and Regional Markets at the Year 2030, Relative to Baseline and Alternative Baseline

Economic Measures (all dollar values in 2018$)	Baseline	Option 2 without ACE: Value	Option 2 without ACE: Diff.	Option 2 without ACE: % Change	Alternative Baseline	Option 2 with ACE: Value	Option 2 with ACE: Diff.	Option 2 with ACE: % Change
NOx Emissions (Million Tons)	0.036	0.036	0.000	0.0%	0.037	0.037	0.000	0.1%
SO2 Emissions (Million Tons)	0.021	0.020	0.000	-0.7%	0.021	0.021	0.000	0.0%
HCL Emissions (Million Tons)	0.000	0.000	0.000	-0.4%	0.000	0.000	0.000	0.0%
Midwest Reliability Organization (MRO)								
Total Domestic Capacity (GW)	67.7	67.6	-0.1	-0.1%	67.7	67.6	0.0	0.0%
Existing			0.0	0.0%			0.0	0.0%
New Additions			-0.1	-0.1%			0.0	0.0%
Early Retirements			0.0	0.0%			0.0	0.0%
Wholesale Price ($/MWh)	$40.03	$39.88	-$0.15	-0.4%	$39.87	$39.84	-$0.03	-0.1%
Generation (TWh)	272	272	0.2	0.1%	272	273	0	0.1%
Costs ($Millions)	$8,822	$8,821	-$2	0.0%	$8,856	$8,857	$0	0.0%
Fuel Cost	$3,651	$3,659	$8	0.2%	$3,627	$3,637	$11	0.3%
Variable O&M	$763	$761	-$2	-0.2%	$770	$768	-$2	-0.2%
Fixed O&M	$2,890	$2,887	-$3	-0.1%	$2,943	$2,936	-$7	-0.2%
Capital Cost	$1,518	$1,513	-$5	-0.3%	$1,517	$1,515	-$2	-0.1%
Variable Production Cost ($/MWh)	$16.23	$16.24	$0.01	0.1%	$16.14	$16.15	$0.01	0.1%
CO2 Emissions (Million Metric Tons)	134.1	134.5	0.4	0.3%	133.4	133.8	0.4	0.3%
Mercury Emissions (Tons)	0.39	0.39	0.00	0.3%	0.39	0.39	0.00	0.3%
NOx Emissions (Million Tons)	0.090	0.091	0.001	1.1%	0.090	0.091	0.001	0.9%
SO2 Emissions (Million Tons)	0.089	0.090	0.001	0.7%	0.089	0.090	0.001	0.6%
HCL Emissions (Million Tons)	0.001	0.001	0.000	0.3%	0.001	0.001	0.000	0.3%
Northeast Power Coordinating Council (NPCC)								
Total Domestic Capacity (GW)	79.7	79.5	-0.1	-0.2%	79.6	79.9	0.3	0.3%
Existing			-0.1	-0.2%			0.1	0.2%
New Additions			0.0	0.0%			0.1	0.1%
Early Retirements			0.1	0.2%			-0.1	-0.2%
Wholesale Price ($/MWh)	$42.62	$42.62	$0.00	0.0%	$42.47	$42.59	$0.12	0.3%
Generation (TWh)	238	238	0.0	0.0%	238	238	0	0.1%
Costs ($Millions)	$9,840	$9,841	$1	0.0%	$9,830	$9,842	$12	0.1%
Fuel Cost	$3,343	$3,345	$2	0.1%	$3,343	$3,346	$3	0.1%
Variable O&M	$390	$391	$0	0.1%	$391	$391	$0	-0.1%
Fixed O&M	$3,748	$3,747	-$1	0.0%	$3,749	$3,748	-$1	0.0%
Capital Cost	$2,359	$2,358	-$1	0.0%	$2,347	$2,357	$10	0.4%
Variable Production Cost ($/MWh)	$15.67	$15.68	$0.01	0.0%	$15.68	$15.68	$0.00	0.0%
CO2 Emissions (Million Metric Tons)	47.3	47.3	0.0	0.1%	47.3	47.3	0.0	0.1%
Mercury Emissions (Tons)	0.31	0.31	0.00	0.0%	0.31	0.31	0.00	0.0%
NOx Emissions (Million Tons)	0.029	0.029	0.000	0.0%	0.029	0.029	0.000	0.0%
SO2 Emissions (Million Tons)	0.004	0.004	0.000	0.0%	0.004	0.004	0.000	0.0%
HCL Emissions (Million Tons)	0.000	0.000	0.000	0.0%	0.000	0.000	0.000	0.0%

Table C-3: Impact of Proposed ELG Option 2 on National and Regional Markets at the Year 2030, Relative to Baseline and Alternative Baseline

Economic Measures (all dollar values in 2018$)	Baseline	Option 2 without ACE			Alternative Baseline	Option 2 with ACE		
		Value	Diff.	% Change		Value	Diff.	% Change
ReliabilityFirst Corporation (RFC)								
Total Domestic Capacity (GW)	223.4	222.9	-0.4	-0.2%	223.8	223.4	-0.4	-0.2%
Existing			0.0	0.0%			0.0	0.0%
New Additions			-0.5	-0.2%			-0.5	-0.2%
Early Retirements			0.0	0.0%			0.0	0.0%
Wholesale Price ($/MWh)	$40.66	$40.62	-$0.04	-0.1%	$40.59	$40.61	$0.02	0.0%
Generation (TWh)	928	927	-0.9	-0.1%	929	927	-2	-0.2%
Costs ($Millions)	$35,545	$35,434	-$111	-0.3%	$35,679	$35,524	-$155	-0.4%
Fuel Cost	$15,878	$15,882	$3	0.0%	$15,796	$15,830	$34	0.2%
Variable O&M	$2,470	$2,469	-$1	0.0%	$2,459	$2,467	$8	0.3%
Fixed O&M	$12,112	$12,047	-$65	-0.5%	$12,233	$12,105	-$128	-1.1%
Capital Cost	$5,085	$5,036	-$49	-1.0%	$5,190	$5,122	-$68	-1.3%
Variable Production Cost ($/MWh)	$19.78	$19.80	$0.02	0.1%	$19.64	$19.73	$0.09	0.4%
CO2 Emissions (Million Metric Tons)	404.0	404.9	0.9	0.2%	399.9	402.1	2.2	0.6%
Mercury Emissions (Tons)	1.13	1.13	0.01	0.5%	1.11	1.12	0.01	1.1%
NOx Emissions (Million Tons)	0.219	0.219	0.000	0.1%	0.215	0.216	0.002	0.7%
SO2 Emissions (Million Tons)	0.227	0.227	0.000	0.1%	0.224	0.226	0.001	0.5%
HCL Emissions (Million Tons)	0.001	0.001	0.000	0.3%	0.001	0.001	0.000	0.9%
Southeast Electric Reliability Council (SERC)								
Total Domestic Capacity (GW)	272.9	274.3	1.4	0.5%	272.9	275.4	2.5	0.9%
Existing			1.7	0.6%			2.8	1.0%
New Additions			-0.3	-0.1%			-0.3	-0.1%
Early Retirements			-1.7	-0.6%			-2.8	-1.0%
Wholesale Price ($/MWh)	$43.65	$43.52	-$0.14	-0.3%	$43.66	$43.54	-$0.11	-0.3%
Generation (TWh)	1,132	1,133	0.9	0.1%	1,131	1,133	2	0.2%
Costs ($Millions)	$43,758	$43,756	-$3	0.0%	$43,814	$43,861	$47	0.1%
Fuel Cost	$21,512	$21,537	$25	0.1%	$21,374	$21,436	$62	0.3%
Variable O&M	$2,684	$2,688	$4	0.2%	$2,682	$2,688	$7	0.2%
Fixed O&M	$15,895	$15,901	$5	0.0%	$15,990	$16,013	$23	0.1%
Capital Cost	$3,667	$3,630	-$37	-1.0%	$3,769	$3,724	-$45	-1.2%
Variable Production Cost ($/MWh)	$21.37	$21.38	$0.01	0.0%	$21.27	$21.30	$0.03	0.1%
CO2 Emissions (Million Metric Tons)	418.7	420.9	2.2	0.5%	415.4	418.2	2.8	0.7%
Mercury Emissions (Tons)	0.77	0.78	0.01	1.3%	0.76	0.77	0.01	1.2%
NOx Emissions (Million Tons)	0.197	0.199	0.002	1.1%	0.195	0.197	0.002	1.1%
SO2 Emissions (Million Tons)	0.297	0.300	0.003	0.9%	0.294	0.298	0.004	1.4%
HCL Emissions (Million Tons)	0.001	0.001	0.000	1.8%	0.001	0.001	0.000	1.7%

Table C-3: Impact of Proposed ELG Option 2 on National and Regional Markets at the Year 2030, Relative to Baseline and Alternative Baseline

Economic Measures (all dollar values in 2018$)	Baseline	Option 2 without ACE			Alternative Baseline	Option 2 with ACE		
		Value	Diff.	% Change		Value	Diff.	% Change
Southwest Power Pool (SPP)								
Total Domestic Capacity (GW)	79.2	79.1	-0.1	-0.1%	78.9	79.1	0.2	0.2%
Existing			0.0	0.0%			0.2	0.3%
New Additions			-0.1	-0.1%			-0.1	-0.1%
Early Retirements			0.0	0.0%			-0.2	-0.3%
Wholesale Price ($/MWh)	$40.97	$40.96	-$0.01	0.0%	$41.05	$41.03	-$0.01	0.0%
Generation (TWh)	269	269	-0.1	0.0%	269	269	0	-0.1%
Costs ($Millions)	$8,476	$8,460	-$16	-0.2%	$8,469	$8,453	-$16	-0.2%
Fuel Cost	$4,135	$4,144	$9	0.2%	$4,124	$4,130	$6	0.2%
Variable O&M	$765	$765	$1	0.1%	$776	$776	$0	0.0%
Fixed O&M	$2,658	$2,647	-$10	-0.4%	$2,694	$2,684	-$10	-0.4%
Capital Cost	$918	$903	-$15	-1.7%	$875	$862	-$13	-1.5%
Variable Production Cost ($/MWh)	$18.22	$18.26	$0.04	0.2%	$18.23	$18.26	$0.03	0.2%
CO2 Emissions (Million Metric Tons)	132.1	132.3	0.3	0.2%	131.8	132.0	0.1	0.1%
Mercury Emissions (Tons)	0.32	0.32	0.00	0.2%	0.32	0.32	0.00	0.0%
NOx Emissions (Million Tons)	0.080	0.081	0.000	0.3%	0.080	0.080	0.000	0.1%
SO2 Emissions (Million Tons)	0.112	0.112	0.000	0.1%	0.111	0.111	0.000	-0.1%
HCL Emissions (Million Tons)	0.000	0.000	0.000	0.2%	0.000	0.000	0.000	0.1%
Electric Reliability Organization of Texas (TRE)								
Total Domestic Capacity (GW)	118.9	118.9	0.0	0.0%	119.1	119.0	0.0	0.0%
Existing			0.0	0.0%			0.0	0.0%
New Additions			0.0	0.0%			0.0	0.0%
Early Retirements			0.0	0.0%			0.0	0.0%
Wholesale Price ($/MWh)	$40.69	$40.69	$0.00	0.0%	$40.72	$40.71	-$0.01	0.0%
Generation (TWh)	416	416	0.0	0.0%	416	416	0	0.0%
Costs ($Millions)	$14,535	$14,531	-$4	0.0%	$14,560	$14,552	-$7	-0.1%
Fuel Cost	$7,121	$7,127	$6	0.1%	$7,068	$7,075	$7	0.1%
Variable O&M	$855	$856	$1	0.1%	$860	$861	$1	0.1%
Fixed O&M	$4,690	$4,686	-$4	-0.1%	$4,734	$4,729	-$4	-0.1%
Capital Cost	$1,869	$1,862	-$7	-0.4%	$1,898	$1,887	-$11	-0.6%
Variable Production Cost ($/MWh)	$19.16	$19.17	$0.01	0.1%	$19.04	$19.06	$0.02	0.1%
CO2 Emissions (Million Metric Tons)	149.2	149.4	0.1	0.1%	148.3	148.4	0.2	0.1%
Mercury Emissions (Tons)	0.43	0.43	0.00	0.1%	0.43	0.43	0.00	0.1%
NOx Emissions (Million Tons)	0.064	0.065	0.000	0.1%	0.064	0.064	0.000	0.2%
SO2 Emissions (Million Tons)	0.073	0.075	0.002	2.8%	0.073	0.073	-0.001	-0.8%
HCL Emissions (Million Tons)	0.000	0.000	0.000	0.2%	0.000	0.000	0.000	0.2%

Table C-3: Impact of Proposed ELG Option 2 on National and Regional Markets at the Year 2030, Relative to Baseline and Alternative Baseline

Economic Measures (all dollar values in 2018$)	Baseline	Option 2 without ACE			Alternative Baseline	Option 2 with ACE		
		Value	Diff.	% Change		Value	Diff.	% Change
Western Electricity Coordinating Council (WECC)								
Total Domestic Capacity (GW)	241.2	241.2	0.0	0.0%	241.6	241.6	0.0	0.0%
Existing			0.0	0.0%			0.0	0.0%
New Additions			0.0	0.0%			0.0	0.0%
Early Retirements			0.0	0.0%			0.0	0.0%
Wholesale Price ($/MWh)	$46.53	$46.55	$0.02	0.0%	$46.53	$46.56	$0.04	0.1%
Generation (TWh)	775	775	0	0.0%	775	775	0	0.0%
Costs ($Millions)	$25,533	$25,536	$3	0.0%	$25,567	$25,565	-$2	0.0%
Fuel Cost	$7,668	$7,673	$4	0.1%	$7,654	$7,658	$4	0.1%
Variable O&M	$1,729	$1,728	-$1	-0.1%	$1,730	$1,728	-$2	-0.1%
Fixed O&M	$8,279	$8,279	$0	0.0%	$8,331	$8,328	-$3	0.0%
Capital Cost	$7,857	$7,856	$0	0.0%	$7,852	$7,851	-$1	0.0%
Variable Production Cost ($/MWh)	$12.12	$12.13	$0.00	0.0%	$12.11	$12.11	$0.00	0.0%
CO2 Emissions (Million Metric Tons)	198.8	198.8	0.0	0.0%	197.6	197.5	-0.1	-0.1%
Mercury Emissions (Tons)	0.89	0.89	0.00	0.0%	0.88	0.88	0.00	0.0%
NOx Emissions (Million Tons)	0.094	0.094	0.000	0.1%	0.093	0.093	0.000	-0.2%
SO2 Emissions (Million Tons)	0.063	0.063	0.000	-0.1%	0.063	0.063	0.000	-0.1%
HCL Emissions (Million Tons)	0.001	0.001	0.000	0.0%	0.001	0.001	0.000	-0.2%

a. Numbers may not add up due to rounding.

Source: U.S. EPA Analysis, 2019

Impacts on Steam Electric Power Plants as a Group

Table C-4 summarizes the impact on the subset of plants to which the ELGs apply, *i.e.*, steam electric power plants. For the group of steam electric power plants, total capacity increases by 3,107 MW or approximately 0.9 percent of the 336,547 MW in alternative baseline capacity. This increase is almost entirely attributable to avoided retirements in the SERC region (2,815 MW, 13.5 percent), with additional avoided retirements in the SPP and RFC regions. There is one net closure in the RFC region, which is no longer offset by an avoided closure in the SERC region, yielding one net closure at the national level for this sensitivity analysis.

Total generation by steam electric plants is estimated to increase by 7,345 GWh (0.5 percent), which is slightly more than was predicted for the scenario detailed in Chapter 5. As was the case for the scenario without ACE, steam electric plants in the SERC and RFC regions are projected to experience the largest increases in generation under Option 2, while plants in other regions see smaller increases and those in WECC experience negligible decreases in generation.

The increase in generation is accompanied by a net increase in total costs for steam electric plants of $191 million at the national level (0.3 percent). The distribution of these cost increases is generally consistent with results from the scenario detailed in Chapter 5. However, in the RFC region there is an increase in costs of $51 million (0.4 percent) in the scenario with ACE compared to a decrease in costs of $30 million (0.2 percent) relative to the baseline. At the national level, variable production costs for steam electric power plants increase by $0.02 per MWh (0.1 percent), which is the same increase predicted for the scenario without ACE. Effects vary by region, with changes ranging from -$0.01 per MWh in MRO to $0.06 per MWh in SERC.

Table C-4: Impact of Proposed ELG Option 2 on In-Scope Plants, as a Group, at the Year 2030, Relative to Baseline and Alternative Baseline

Economic Measures (all dollar values in 2018$)	Baseline	Option 2 without ACE			Alternative Baseline	Option 2 with ACE		
		Value	Difference	% Change		Value	Difference	% Change
National Totals								
Total Domestic Capacity (MW)	336,872	339,752	2,880	0.9%	336,547	339,654	3,107	0.9%
Early Retirements - Number of Plants	79	79	0	0.0%	78	79	1	1.3%
Full & Partial Retirements - Capacity (MW)	58,192	55,312	-2,880	-4.9%	58,518	55,411	-3,107	-5.3%
Generation (GWh)	1,570,513	1,575,189	4,676	0.3%	1,569,109	1,576,455	7,345	0.5%
Costs ($Millions)	$60,298	$60,397	$98	0.2%	$60,387	$60,578	$191	0.3%
Fuel Cost	$34,842	$34,976	$134	0.4%	$34,557	$34,765	$208	0.6%
Variable O&M	$5,987	$5,999	$12	0.2%	$6,000	$6,020	$20	0.3%
Fixed O&M	$19,165	$19,117	-$48	-0.3%	$19,533	$19,497	-$36	-0.2%
Capital Cost	$304	$304	$0	0.1%	$297	$296	-$2	-0.6%
Variable Production Cost ($/MWh)	$26.00	$26.01	$0.02	0.1%	$25.85	$25.87	$0.02	0.1%
Florida Reliability Coordinating Council (FRCC)								
Total Domestic Capacity (MW)	27,584	27,584	0	0.0%	27,584	27,584	0	0.0%
Early Retirements - Number of Plants	1	1	0	0.0%	1	1	0	0.0%
Full & Partial Retirements - Capacity (MW)	869	869	0	0.0%	869	869	0	0.0%
Generation (GWh)	126,731	126,692	-39	0.0%	127,531	127,540	9	0.0%
Costs ($Millions)	$5,271	$5,266	-$5	-0.1%	$5,308	$5,305	-$3	-0.1%
Fuel Cost	$3,631	$3,630	-$1	0.0%	$3,645	$3,645	$1	0.0%
Variable O&M	$317	$317	$0	0.0%	$322	$322	$0	0.1%
Fixed O&M	$1,323	$1,319	-$4	-0.3%	$1,342	$1,338	-$4	-0.3%
Capital Cost	$0	$0	$0	NA	$0	$0	$0	NA
Variable Production Cost ($/MWh)	$31.15	$31.15	$0.00	0.0%	$31.10	$31.11	$0.01	0.0%

Table C-4: Impact of Proposed ELG Option 2 on In-Scope Plants, as a Group, at the Year 2030, Relative to Baseline and Alternative Baseline

Economic Measures (all dollar values in 2018$)	Baseline	Option 2 without ACE			Alternative Baseline	Option 2 with ACE		
		Value	Difference	% Change		Value	Difference	% Change
Midwest Reliability Organization (MRO)								
Total Domestic Capacity (MW)	24,324	24,324	0	0.0%	24,308	24,308	0	0.0%
Early Retirements - Number of Plants	7	7	0	0.0%	7	7	0	0.0%
Full & Partial Retirements - Capacity (MW)	4,402	4,402	0	0.0%	4,418	4,418	0	0.0%
Generation (GWh)	139,319	139,622	303	0.2%	139,718	140,143	425	0.3%
Costs ($Millions)	$4,828	$4,832	$4	0.1%	$4,863	$4,865	$3	0.1%
Fuel Cost	$2,760	$2,768	$8	0.3%	$2,738	$2,749	$11	0.4%
Variable O&M	$647	$645	-$2	-0.3%	$654	$652	-$2	-0.3%
Fixed O&M	$1,345	$1,343	-$3	-0.2%	$1,395	$1,388	-$7	-0.5%
Capital Cost	$76	$76	$0	0.0%	$76	$76	$0	0.0%
Variable Production Cost ($/MWh)	$24.45	$24.45	-$0.01	0.0%	$24.28	$24.27	-$0.01	0.0%
Northeast Power Coordinating Council (NPCC)								
Total Domestic Capacity (MW)	11,120	11,120	0	0.0%	11,120	11,120	0	0.0%
Early Retirements - Number of Plants	3	3	0	0.0%	3	3	0	0.0%
Full & Partial Retirements - Capacity (MW)	2,708	2,708	0	0.0%	2,708	2,708	0	0.0%
Generation (GWh)	27,573	27,606	34	0.1%	27,592	27,652	60	0.2%
Costs ($Millions)	$1,309	$1,310	$1	0.1%	$1,310	$1,312	$2	0.2%
Fuel Cost	$608	$609	$1	0.1%	$609	$610	$2	0.3%
Variable O&M	$43	$43	$0	0.1%	$43	$43	$0	0.2%
Fixed O&M	$658	$658	$0	0.0%	$658	$658	$0	0.0%
Capital Cost	$0	$0	$0	NA	$0	$0	$0	NA
Variable Production Cost ($/MWh)	$23.62	$23.63	$0.00	0.0%	$23.62	$23.64	$0.02	0.1%
ReliabilityFirst Corporation (RFC)								
Total Domestic Capacity (MW)	76,002	76,016	14	0.0%	75,643	75,691	48	0.1%
Early Retirements - Number of Plants	35	36	1	2.9%	35	36	1	2.9%
Full & Partial Retirements - Capacity (MW)	21,956	21,942	-14	-0.1%	22,317	22,269	-48	-0.2%
Generation (GWh)	364,667	365,423	756	0.2%	361,432	364,656	3,224	0.9%
Costs ($Millions)	$13,982	$13,951	-$30	-0.2%	$13,907	$13,958	$51	0.4%
Fuel Cost	$8,038	$8,046	$8	0.1%	$7,902	$7,978	$77	1.0%
Variable O&M	$1,606	$1,605	-$1	-0.1%	$1,588	$1,599	$10	0.7%
Fixed O&M	$4,304	$4,265	-$38	-0.9%	$4,388	$4,352	-$37	-0.8%
Capital Cost	$35	$36	$1	2.8%	$29	$29	$0	0.6%

Table C-4: Impact of Proposed ELG Option 2 on In-Scope Plants, as a Group, at the Year 2030, Relative to Baseline and Alternative Baseline

Economic Measures (all dollar values in 2018$)	Baseline	Option 2 without ACE			Alternative Baseline	Option 2 with ACE		
		Value	Difference	% Change		Value	Difference	% Change
Variable Production Cost ($/MWh)	$26.44	$26.41	-$0.04	-0.1%	$26.26	$26.26	$0.01	0.0%
Southeast Electric Reliability Council (SERC)								
Total Domestic Capacity (MW)	103,935	106,801	2,866	2.8%	103,986	106,801	2,815	2.7%
Early Retirements - Number of Plants	17	16	-1	-5.9%	16	16	0	0.0%
Full & Partial Retirements - Capacity (MW)	20,836	17,970	-2,866	-13.8%	20,785	17,970	-2,815	-13.5%
Generation (GWh)	479,646	482,880	3,235	0.7%	478,413	481,896	3,483	0.7%
Costs ($Millions)	$19,139	$19,265	$126	0.7%	$19,116	$19,265	$149	0.8%
Fuel Cost	$11,129	$11,232	$103	0.9%	$11,024	$11,133	$109	1.0%
Variable O&M	$1,630	$1,646	$15	0.9%	$1,629	$1,641	$13	0.8%
Fixed O&M	$6,313	$6,320	$7	0.1%	$6,396	$6,423	$28	0.4%
Capital Cost	$67	$67	$0	0.0%	$67	$67	$0	0.0%
Variable Production Cost ($/MWh)	$26.60	$26.67	$0.07	0.3%	$26.45	$26.51	$0.06	0.2%
Southwest Power Pool (SPP)								
Total Domestic Capacity (MW)	26,885	26,885	0	0.0%	26,885	27,129	244	0.9%
Early Retirements - Number of Plants	3	3	0	0.0%	3	3	0	0.0%
Full & Partial Retirements - Capacity (MW)	1,879	1,879	0	0.0%	1,879	1,635	-244	-13.0%
Generation (GWh)	116,430	116,717	288	0.2%	117,564	117,705	141	0.1%
Costs ($Millions)	$4,394	$4,395	$1	0.0%	$4,440	$4,438	-$2	-0.1%
Fuel Cost	$2,635	$2,642	$7	0.3%	$2,623	$2,627	$4	0.2%
Variable O&M	$582	$582	$0	0.1%	$592	$592	$0	0.0%
Fixed O&M	$1,163	$1,156	-$6	-0.5%	$1,210	$1,203	-$6	-0.5%
Capital Cost	$15	$15	$0	0.4%	$15	$15	$0	0.0%
Variable Production Cost ($/MWh)	$27.63	$27.63	$0.00	0.0%	$27.35	$27.35	$0.00	0.0%
Texas Regional Entity (TRE)								
Total Domestic Capacity (MW)	25,945	25,945	0	0.0%	25,945	25,945	0	0.0%
Early Retirements - Number of Plants	1	1	0	0.0%	1	1	0	0.0%
Full & Partial Retirements - Capacity (MW)	391	391	0	0.0%	391	391	0	0.0%
Generation (GWh)	114,229	114,369	140	0.1%	114,785	114,929	144	0.1%
Costs ($Millions)	$4,497	$4,498	$1	0.0%	$4,533	$4,534	$1	0.0%
Fuel Cost	$2,499	$2,504	$4	0.2%	$2,487	$2,490	$4	0.1%
Variable O&M	$441	$441	$1	0.1%	$448	$449	$1	0.2%

Table C-4: Impact of Proposed ELG Option 2 on In-Scope Plants, as a Group, at the Year 2030, Relative to Baseline and Alternative Baseline

Economic Measures (all dollar values in 2018$)	Baseline	Option 2 without ACE			Alternative Baseline	Option 2 with ACE		
		Value	Difference	% Change		Value	Difference	% Change
Fixed O&M	$1,557	$1,553	-$3	-0.2%	$1,598	$1,594	-$3	-0.2%
Capital Cost	$0	$0	$0	NA	$0	$0	$0	NA
Variable Production Cost ($/MWh)	$25.74	$25.75	$0.01	0.0%	$25.57	$25.57	$0.01	0.0%
Western Electricity Coordinating Council (WECC)								
Total Domestic Capacity (MW)	41,077	41,077	0	0.0%	41,077	41,077	0	0.0%
Early Retirements - Number of Plants	12	12	0	0.0%	12	12	0	0.0%
Full & Partial Retirements - Capacity (MW)	5,151	5,151	0	0.0%	5,151	5,151	0	0.0%
Generation (GWh)	201,919	201,879	-40	0.0%	202,075	201,934	-141	-0.1%
Costs ($Millions)	$6,877	$6,878	$1	0.0%	$6,910	$6,901	-$9	-0.1%
Fuel Cost	$3,541	$3,545	$4	0.1%	$3,530	$3,531	$1	0.0%
Variable O&M	$721	$720	-$1	-0.2%	$723	$721	-$2	-0.2%
Fixed O&M	$2,502	$2,502	$0	0.0%	$2,547	$2,540	-$7	-0.3%
Capital Cost	$112	$111	-$1	-0.6%	$111	$109	-$2	-1.8%
Variable Production Cost ($/MWh)	$21.11	$21.13	$0.01	0.1%	$21.04	$21.06	$0.01	0.1%

a. Numbers may not add up due to rounding.

Source: U.S. EPA Analysis, 2019.

Impacts on Individual Steam Electric Power Plants

Table C-5 presents the estimated number of steam electric power plants with specific degrees of change in operations and financial performance as a result of proposed Option 2 when analyzed relative to the two baselines.

The indicators of changes across individual steam electric plants are generally similar when assessed against either baseline. The results indicate that most plants experience only slight effects – *i.e.*, no change or less than a one percent reduction or one percent increase. Six plants (1 percent) are estimated to incur a reduction in capacity utilization of at least one percent and 28 plants (4 percent) incur a reduction in generation of at least one percent. Finally, only 2 plants (0.3 percent) are estimated to incur an increase in variable production costs of at least one percent.

Table C-5: Impact of Proposed ELG Option 2 on Individual In-Scope Plants at the Year 2030, Relative to Baseline and Alternative Baseline

Economic Measures	Reduction			No Change	Increase			N/A[b,c]
	> 3%	≥1% and <3%	<1%		<1%	≥1% and <3%	≥3%	
Option 2 without ACE, Relative to Baseline								
Change in Capacity Utilization[a]	4	5	44	277	63	9	3	281
Change in Generation	17	9	27	277	43	14	18	281
Change in Variable Production Costs/MWh	2	7	94	197	64	2	1	319
Option 2 with ACE, Relative to Alternative Baseline								
Change in Capacity Utilization[a]	2	4	48	271	55	18	6	282
Change in Generation	17	11	26	272	38	21	19	282
Change in Variable Production Costs/MWh	2	10	81	191	81	2	0	319

a. The change in capacity utilization is the difference between the capacity utilization percentages in the baseline and policy cases. For all other measures, the change is expressed as the percentage change between the baseline and policy values.

Source: U.S. EPA Analysis, 2019