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

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AEO	Annual Energy Outlook
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
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CCI	Construction cost index
CCP	Clean Power Plan
CCR	Coal combustion residuals
CSAPR	Cross-State Air Pollution Rule
CWA	Clean Water Act
DCN	Document control number
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
FGMC	Flue gas mercury control
FR	Federal Register
GDP	Gross domestic product
IPM	Integrated Planning Model
MATS	Mercury and Air Toxics Standards
NAAQS	National Ambient Air Quality Standards
NAICS	North American Industry Classification System
NERC	North American Electric Reliability Corporation
NPDES	National Pollutant Discharge Elimination System
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
SBA	Small Business Administration
SBREFA	Small Business Regulatory Enforcement Fairness Act
TDD	Technical Development Document
UMRA	Unfunded Mandates Reform Act

1 Introduction

1.1 Background

EPA is promulgating a regulation that strengthens the existing controls on discharges from steam electric power plants by revising technology-based effluent limitations guidelines and standards (ELGs) for the steam electric power generating point source category, 40 CFR part 423.

The final effluent limitation guidelines and standards 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. 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 EPA's requirements for objectivity, integrity and utility, and are appropriate for the intended use.

This document describes EPA's analysis of the costs and economic impacts of the final ELGs. 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:

- Technical Development Document for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (TDD) (U.S. EPA, 2015c; DCN SE05904). The TDD provides background on the final ELGs; applicability and summary of the final ELGs; industry description; wastewater characterization and identifying pollutants of concern; and treatment technologies and pollution prevention techniques. It also documents EPA's engineering analyses to support the final ELGs including facility specific compliance cost estimates, pollutant loadings, and non-water quality impact assessment.
- Benefit and Cost Analysis for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (BCA) (U.S. EPA, 2015a; DCN SE05977). The BCA summarizes the societal benefits and costs expected to result from implementation of the final ELGs.
- Environmental Assessment for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (EA) (U.S. EPA, 2015b; DCN SE04527). The EA summarizes the environmental and human health improvements that are expected to result from implementation of the final ELGs.

1.2 Overview of the Economic and Benefits Analysis of the Final ELGs

The following sections describe the key components of the final ELGs analysis framework.

EPA's analysis of the final ELGs generally follows the methodology the Agency previously used to analyze the proposed ELGs (see *Regulatory Impact Analysis for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (U.S. EPA, 2013b; DCN

SE03170). *Appendix D* describes the principal changes to the final ELGs analysis, as compared to the proposed ELGs analysis. They include:

- Updating the cost inputs to reflect revised option definitions and compliance cost estimates (see *TDD* for details)
- Updating the universe of steam electric power plants and their wastestreams to account for conversions, retirements, and other changes that have occurred, have been announced or are projected in response to environmental regulations or other changes.
- Using the most recent Integrated Planning Model platform (IPM v5.13 vs. IPM v4.10) to evaluate the impact of the ELG on the electricity markets. IPM v5.13 incorporates the effects of regulations and programs that will be in effect by the time the final ELGs are implemented, including the final Cooling Water Intake Structure (CWIS) Rule for Existing Electric Generating Plants and Factories, the Final Coal Combustion Residuals (CCR) rule, and the Clean Power Plan (CPP) rule.
- Updating the analysis year (2015 vs. 2014) and dollar year (2013 dollars vs. 2010 dollars).
- Updating electricity generation, sales, and electricity prices based on the most current data from EIA (2012 vs. 2009).
- Updating the SBA small business size thresholds (July 2014 standards vs. October 2012 standards) and recategorizing entities that own steam electric power plants as small or large.
- Making other updates to address comments the Agency received on the proposed rule and to improve insight on the effects of the ELGs on employment and distributional impacts.

1.2.1 Steam Electric Power Plants

The final rule establishes new limitations and standards for plants subject to the previously established ELGs for the Steam Electric Power Generating Point Source Category. The ELGs apply to a subset of the electric power industry, namely those plants with discharges resulting from the operation of a generating unit "primarily engaged in the generation of electricity for distribution and/or sale, which results primarily from a process utilizing fossil-type fuels (coal, petroleum coke, oil, gas) or nuclear fuel in conjunction with a thermal cycle employing the steam water system as the thermodynamic medium."[1]

Based on data EPA obtained from the 2010 Questionnaire for the Steam Electric Power Generating Effluent Guidelines (industry survey; U.S. EPA, 2010a) and other sources (see TDD), EPA estimates that there were 1,080 steam electric power plants in 2009.[2] As presented in *Table 1-1*, the 1,080 steam electric power plants represent approximately 19 percent of the total number of plants in the power generation sector, but represent approximately 70 percent of the national total electric generating capacity with 787,108 MW. For more detail

[1] The final rule contains three minor modifications to the wording of the previously established applicability provision in the steam electric power generating ELGs to reflect EPA's longstanding interpretation and implementation of the rule. These revisions do not alter the universe of generating units regulated by the ELGs, nor do they impose compliance costs on the industry. Instead, they remove potential ambiguity in the regulations by revising the text to more clearly reflect EPA's longstanding interpretation. See Section VIII of the preamble for more details.

[2] The industry survey EPA conducted in 2010 requested data for several years of operation, up to the most recent complete calendar year at the time the survey was conducted: 2009.

on the electric generating industry and on steam electric power plants to which the final ELGs apply, see *Chapter 2: Profile of the Electric Power Industry*.

Table 1-1: Steam Electric Industry Share of Total Electric Power Generation Existing Parent Entities, Plants, and Capacity in 2012

		Steam Electric Industry[b,c]	
	Total[a]	Number	% of Total
Parent Entities	2,657	243	9.1%
Plants	5,679	1,080	19.0%
Capacity (MW)	1,121,686	787,108	70.2%

a. Data for total electric power generation industry are from the 2012 EIA-860 database (U.S. DOE, 2012b) and 2012 EIA-861 database (U.S. DOE, 2012c).

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

c. The steam electric industry parent entities count (243 entities) is based on the lower bound estimate of the number of steam electric power plant owners (for details, see *Chapter 4: Cost and Economic Impact Screening Analyses*). EPA estimates at 507 the upper bound number of steam electric power plant owners.
Source: U.S. EPA Analysis, 2015; U.S. DOE, 2012b; U.S. DOE, 2012c.

Of the 1,080 steam electric power plants in the universe, only a subset are expected to incur compliance costs as a result of the final ELGs, based on their operations. While almost all steam electric power plants generate wastewater, like cooling water and boiler blowdown, the presence of certain wastestreams is dependent on the type of fuel burned. Coal- and petroleum coke-fired generating units, and to a lesser degree oil-fired generating units, produce a flue gas stream that contains large quantities of particulate matter, sulfur dioxide, and nitrogen oxides, which would be emitted to the atmosphere if they were not cleaned from the flue gas prior to emission. Many of these generating units are therefore outfitted with air pollution control systems (*e.g.*, particulate removal systems, flue gas desulfurization (FGD) systems, NOx removal systems, and mercury control systems). Gas-fired generating units generate fewer emissions of particulate matter, sulfur dioxide, and nitrogen oxides than coal- or oil-fired generating units, and therefore do not typically operate air pollution control systems to control emissions from their flue gas. In addition, coal and petroleum coke-fired generating units create fly and/or bottom ash as a result of coal combustion. EPA focused this rule on controlling the discharges of wastewaters from FGD wastewater, fly ash transport water, bottom ash transport water, combustion residual leachate from landfills and surface impoundments, wastewater from flue gas mercury control (FGMC) systems and gasification systems. Given this focus and EPA's subcategorization of oil-fired generating units (see Section VIII of the preamble), steam electric power plants incurring costs under the final rule are exclusively coal-fired power plants.

1.2.2 Main Regulatory Options Analyzed for the Final Rule

EPA presents six regulatory options for the final rule. These options differ in the wastestreams controlled by the rule, the size of the units controlled, and the stringency of controls (see *TDD* for a detailed discussion of the options and the associated treatment technology bases). Thus, EPA evaluated revising or establishing Best Available Technology Economically Achievable (BAT), New Source Performance Standards (NSPS), Pretreatment Standards for Existing Sources (PSES), and Pretreatment Standards for New Sources (PSNS) that apply to discharges of up to seven wastestreams: FGD wastewater, fly ash transport water, bottom ash transport water, combustion residual leachate from landfills and surface impoundments, wastewater from FGMC systems, wastewater from gasification systems, and nonchemical metal cleaning wastes.

Table 1-2, on the next page, summarizes six regulatory options evaluated for the final ELGs. EPA is establishing limitations and standards for existing sources (BAT/PSES) based on the technologies in Option

D. For new sources, EPA selected the technologies in Option F as the basis for the NSPS and PSNS. The preamble that accompanies the final rule explains the rationale for EPA's decision.

Table 1-2: Steam Electric ELG Regulatory Options

Wastestream	Technology Basis for BAT/NSPS/PSES/PSNS Regulatory Options					
	A	**B**	**C**	**D**	**E**	**F**
FGD Wastewater	Chemical Precipitation	Chemical Precipitation + Biological Treatment	Chemical Precipitation + Biological Treatment	Chemical Precipitation + Biological Treatment	Chemical Precipitation + Biological Treatment	Evaporation
Fly Ash Transport Water	Dry Handling	Dry Handling	Dry Handling	Dry Handling	Dry Handling	Dry handling
Bottom Ash Transport Water	Impoundment (Equal to BPT)	Impoundment (Equal to BPT)	Dry handling / Closed loop (for units >400 MW); Impoundment (Equal to BPT)(for units ≤400 MW)	Dry Handling / Closed loop	Dry Handling / Closed loop	Dry handling / Closed loop
FGMC Wastewater	Dry Handling	Dry Handling	Dry Handling	Dry Handling	Dry Handling	Dry handling
Gasification Wastewater	Evaporation	Evaporation	Evaporation	Evaporation	Evaporation	Evaporation
Combustion Residual Leachate	Impoundment (Equal to BPT)	Impoundment (Equal to BPT)	Impoundment (Equal to BPT)	Impoundment (Equal to BPT)	Chemical Precipitation	Chemical Precipitation
Nonchemical Metal Cleaning Wastes	[Reserved]	[Reserved]	[Reserved]	[Reserved]	[Reserved]	[Reserved]

Source: U.S. EPA, 2015

In the remainder of this document, EPA presents the analytical results only for Options A through E for existing sources. During development of the final rule, EPA decided not to base the final rule on Option F for existing sources due primarily to the high cost of that Option, particularly in light of the costs associated with other rulemakings expected to impact the steam electric industry (see Section VIII.C.1 of the preamble). As a result, EPA chose not to conduct particular analyses for Option F to the same extent that it did for some of the other options considered.

1.2.3 Analysis Scenarios

EPA made every effort to appropriately account for other rules in its many analyses for this rule. Since proposal, EPA has promulgated several other rules affecting the steam electric industry: the Cooling Water Intake Structures (CWIS) rule for existing facilities (79 FR 48300), the CCR rule (80 FR 21302), the CPP rule (FR publication forthcoming), and the Carbon Pollution Standard for New Power Plants (CPS) rule (FR publication forthcoming). At the time it conducted these analyses, the CPP rule had not yet been finalized, and thus EPA used the proposed CPP rule for its analyses. In some cases, EPA performed two sets of parallel analyses to demonstrate how the other rules affected the final ELGs. For example, EPA conducted an assessment of the final ELGs both with and without accounting for the CPP rule.

The results presented in the main body of this document are based on this scenario with the CPP rule. The results of EPA's analyses without accounting for the CPP rule are presented in *Appendix B*.

EPA also analyzed several other scenarios to evaluate the sensitivity of the results to certain assumptions, notably the effects of EPA's Coal Combustion Residuals (CCR) Final Rule (see *Section 2.5.4*), and subcategorization of oil-fired generating units and small units with generating capacity of 50 MW or less. *Appendix C* presents these sensitivity scenarios.

1.2.4 Cost and Economic Analysis Requirements under the Clean Water Act

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)). EPA's final ELGs respond to these requirements. In establishing national effluent guidelines and pretreatment standards for pollutants, EPA considers the performance of control and treatment technologies and the cost and/or economic achievability of the controls. The economic test differs based on the level of control specified in the ELGs, as summarized below (emphasis added):[3]

- Best Practicable Control Technology Currently Available (BPT) (Section 304(b)(1) of the CWA): Traditionally, EPA establishes effluent limitations based on BPT by reference to the average of the best performances of facilities within the industry, grouped to reflect various ages, sizes, processes, or other common characteristics. EPA can promulgate BPT effluent limitations for conventional, toxic, and nonconventional pollutants. In specifying BPT, EPA looks at a number of factors. EPA first considers the ***cost of achieving effluent reductions in relation to the effluent reduction benefits***. The Agency also considers the age of equipment and facilities, the processes employed, engineering aspects of the control technologies, any required process changes, non-water quality environmental impacts (including energy requirements), and such other factors as the Administrator deems appropriate. See CWA section 304(b)(1)(B). If, however, existing performance is uniformly inadequate, EPA may establish limitations based on higher levels of control than what is currently in place in an industrial category, when based on an Agency determination that the technology is available in another category or subcategory and can be practically applied.

- Best Conventional Pollutant Control Technology (BCT) (Section 304(b)(4) of the CWA): The 1977 amendments to the CWA require EPA to identify additional levels of effluent reduction for conventional pollutants[4] associated with BCT technology for discharges from existing industrial point sources. In addition to other factors specified in section 304(b)(4)(B), the CWA requires that EPA establish BCT limitations after consideration of a ***two-part "cost reasonableness" test***. EPA explained its methodology for the development of BCT limitations in July 9, 1986 (51 FR 24974).

- Best Available Technology Economically Achievable (BAT) (Section 304(b)(2) of the CWA): BAT represents the second level of stringency for controlling direct discharge of toxic and nonconventional

[3] For more information, see either the preamble that accompanies the final rule or EPA's *Industry Effluent Guidelines: Laws and Regulatory Development* web page at http://water.epa.gov/scitech/wastetech/guide/laws.cfm (accessed November 2, 2012).

[4] Section 304(a)(4) designates the following as conventional pollutants: BOD5, total suspended solids (TSS), fecal coliform, pH, and any additional pollutants defined by the Administrator as conventional. The Administrator designated oil and grease as a conventional pollutant on July 30, 1979 (44 FR 44501; 40 CFR 401.16).

pollutants. As the statutory phrase intends, EPA considers the technological availability and the ***economic achievability*** in determining what level of control represents BAT. Other statutory factors that EPA considers in assessing BAT are **the cost** of achieving BAT effluent reductions, the age of equipment and facilities involved, the process employed, potential process changes, and non-water quality environmental impacts (including energy requirements), and such other factors as the Administrator deems appropriate. The Agency retains considerable discretion in assigning the weight to be accorded these factors.[5] Generally, EPA determines economic achievability based on the effect of the cost of compliance with BAT limitations on overall industry and subcategory financial conditions. BAT is intended to reflect the highest performance in the industry, and it may reflect a higher level of performance than is currently being achieved based on technology transferred from a different subcategory or category, bench scale or pilot plant studies, or foreign plants. [6] BAT may be based upon process changes or internal controls, even when these technologies are not common industry practice. [7]

- New Source Performance Standards (NSPS) (Section 306 of the CWA). NSPS reflect "the greatest degree of effluent reduction" that is achievable based on the best available demonstrated control technology (BADCT). Owners of new facilities have the opportunity to install the best and most efficient production processes and wastewater treatment technologies. As a result, NSPS generally represent the most stringent controls attainable through the application of the BADCT for all pollutants (that is, conventional, nonconventional, and toxic pollutants). In establishing NSPS, EPA is directed to ***take into consideration the cost of achieving the effluent reduction*** and any non-water quality environmental impacts and energy requirements.

- Pretreatment Standards for Existing Sources (PSES) (Section 307(b) of the CWA). Section 307(b), 33 U.S.C. 1317(b), of the CWA authorizes EPA to promulgate pretreatment standards for discharges of pollutants to POTWs. PSES are designed to prevent the discharge of pollutants that pass through, interfere with, or are otherwise incompatible with the operation of POTWs. Categorical pretreatment standards are technology-based and are analogous to BPT and BAT effluent limitations guidelines, and thus the Agency typically considers the ***same factors in promulgating PSES as it considers in promulgating BAT***. Congress intended for the combination of pretreatment and treatment by the POTW to achieve the level of treatment that would be required if the industrial source were making a direct discharge.[8] The General Pretreatment Regulations, which set forth the framework for the implementation of categorical pretreatment standards, are found at 40 CFR Part 403. These regulations establish pretreatment standards that apply to all non-domestic dischargers (See 52 FR 1586, January 14, 1987).

- Pretreatment Standards for New Sources (PSNS) (Section 307(c) of the CWA). Section 307(c), 33 U.S.C. 1317(c), of the CWA authorizes EPA to promulgate PSNS at the same time it promulgates NSPS. As is the case for PSES, PSNS are designed to prevent the discharge of any pollutant into a POTW that interferes with, passes through, or is otherwise incompatible with the POTW. In selecting

[5] Weyerhaeuser Co. v. Costle, 590 F.2d 1011, 1045 (D.C. Cir. 1978).

[6] American Paper Inst. v. Train, 543 F.2d 328, 353 (D.C. Cir. 1976); American Frozen Food Inst. v Train, 539 F.2d 107, 132 (D.C. Cir. 1976).

[7] See American Frozen Foods, 539 F.2d at 132, 140; Reynolds Metals Co. v. EPA, 760 F.2d 549, 562 (4th Cir. 1985); California & Hawaiian Sugar Co. v. EPA, 553 F.2d 280, 285-88 (2nd Cir. 1977).

[8] See Conf. Rep. No. 95-830, at 87 (1977), reprinted in U.S. Congress. Senate. Committee on Public Works (1978), A Legislative History of the CWA of 1977, Serial No. 95-14 at 271 (1978).

the PSNS technology basis, the Agency generally considers ***the same factors it considers in establishing NSPS***, along with the results of a pass-through analysis. Like new sources of direct discharges, new sources of indirect discharges have the opportunity to incorporate into their operations the best available demonstrated technologies. As a result, EPA typically promulgates pretreatment standards for new sources based on best available demonstrated control technology for new sources.[9]

In the final ELGs, EPA is establishing effluent limitations guidelines and standards that reflect BAT and PSES for existing sources that discharge directly and indirectly to surface waters, respectively, and NSPS and PSNS for new sources discharging directly and indirectly to surface waters.

This report documents the relevant cost and economic analyses conducted in accordance with CWA requirements. It 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).

1.2.5 Analyses Performed in Support of the Final ELGs and Report Organization

This document discussed the following analyses EPA performed in support of the final ELGs:

- **Compliance cost assessment** (*Chapter 3*), which describes the cost components and calculates the industry-wide compliance costs.
- **Cost and economic impact screening analyses** (*Chapter 4)*, which evaluates the 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 final ELGs using the Integrated Planning Model (IPM) and provides insight into the effects of the final rule on the steam electric power generating industry and on national electricity markets.
- **Analysis of employment effects** (*Chapter 6*), which assesses national-level changes in employment in the steam electric industry.
- **Assessment of potential electricity price effects** (*Chapter 7*), which looks at the 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 impact of the rule on small entities on the basis of a cost-to-revenue comparison
- **Unfunded Mandates Reform Act (UMRA) analysis** (*Chapter 9*) which assesses the 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 EPA to determine if this action would have a significant effect on energy supply, distribution, or use.

[9] See National Association of Metal Finishers v. EPA, 719 F.2d 624, 634 (3rd Cir. 1983)

In addition to these analyses, the document also includes, as a backdrop for regulation development, a profile of the electric power industry and steam electric power plants to which the final ELGs apply (*Chapter 2*). The profile provides information about the operating characteristics of the electric power industry as a whole and of the steam electric power plant universe in particular.

Finally, several appendices provide supporting information:

- *Appendix A: References* provides detailed information on sources cited in the text.
- *Appendix B: Analyses for Alternate Scenario without CPP Rule* summarizes the results of an alternate scenario using a baseline that does not account for the anticipated effects of the CPP rule.
- *Appendix C: Sensitivity Analyses* summarizes results of two alternate scenarios to evaluate the sensitivity of final rule analysis results to two main assumptions. In the analysis described in the main body of this document, EPA (1) accounted for projected conversions from wet to dry systems through 2023 to comply with EPA's 2015 RCRA *Final Rule Regulating Coal Combustion Residual (CCR) Landfills and Surface Impoundments At Coal-Fired Electric Utility Power Plants* ("CCR Final Rule"); and (2) applied BAT and PSES requirements to only those generating units that are not oil-fired, and have more than 50 MW generating capacity. EPA's sensitivity analyses sequentially evaluate alternatives to both assumptions; namely, the analyses either omit projected conversions due to the CCR Final Rule, or apply BAT and PSES requirements to all generating units regardless of the type or generating capacity.
- *Appendix D: Summary of Changes to Costs and Economic Impact Analysis* lists the principal changes EPA made to its costs and economic impact analysis for the final rule, relative to the proposed rule.
- *Appendix E: Overview of IPM and Its Use for the Market Model Analysis of the Final ELGs* describes IPM V5.13, which is the basis of the Market Model Analyses for the final ELG regulatory options discussed in *Chapter 5*.
- *Appendix F: Cost Effectiveness* describes EPA's analysis of the cost-effectiveness of the final ELGs. It also compares the cost-effectiveness of the final ELGs with that of other promulgated ELGs.

2 Profile of the Electric Power Industry

2.1 Introduction

This profile presents economic and operational data for the electric power industry, and for the subset of the industry to which the final ELGs apply (steam electric power plants). It provides information on the structure and overall performance of the industry and describes important trends that may influence the nature and magnitude of economic impacts from the final ELGs.

The electric power industry is one of the most extensively studied of U.S. industries. The Energy Information Administration (EIA), among others, publishes a multitude of reports, documents, and studies on an annual basis which provide information about the operating characteristics of the electric power industry as a whole. As part of this rulemaking, EPA also obtained additional technical and financial information through the 2010 Questionnaire for the Steam Electric Power Generating Effluent Guidelines (industry survey; U.S. EPA, 2010a). The additional information covered topics such as plant processes, operational characteristics, and revenue and costs for steam electric power plants and their parent entities.

This profile is not intended to duplicate existing studies and reports on the industry. Rather, this profile compiles, summarizes, and presents industry data that are important in the context of the final ELGs.

The remainder of this profile is organized as follows:

- *Section 2.2* provides a brief overview of the electric power industry, including descriptions of major industry sectors, types of generating plants, and the entities that own these plants.
- *Section 2.3* provides data on generating capacity, electricity generation, and geographic distribution.
- *Section 2.4* focuses more specifically on steam electric power plants, which are a subset of the overall electric power industry; this section provides information on plant ownership, physical characteristics, and geographic distribution.
- *Section 2.5* provides a brief discussion of factors affecting the future of the electric power industry, including steam electric power plants, most notably the status of electric utility regulatory restructuring and changes in environmental regulations.
- *Section 2.6* summarizes forecasts of market conditions through the year 2035 from the Annual Energy Outlook 2014 (AEO2014).

2.2 Electric Power Industry Overview

This section provides a brief overview of the electric power industry, including descriptions of major industry sectors, types of generating plants, and the entities that own generating plants.

2.2.1 Industry Sectors

The electricity business is made up of three major functional service components or sectors: generation, transmission, and distribution. These terms are defined as follows (Joskow, 1997; U.S. DOE, 2012a):

- The generation sector includes the plants that produce, or "generate," electricity. Electric power is usually produced by a mechanically driven rotary generator. Generator drivers, also called prime movers, include steam turbines; gas- or diesel-powered internal combustion machines; and turbines powered by streams of moving fluid such as water from a hydroelectric dam. Most boilers are heated by direct combustion of fossil or biomass-derived fuels, or waste heat from the exhaust of a gas turbine or diesel engine, but heat from nuclear, solar, and geothermal sources is also used. Electric power may also be produced without a generator by using electrochemical, thermoelectric, or photovoltaic (solar) technologies.

- The transmission sector is the network of large, high-voltage power lines that deliver electricity from plants to local areas. Electricity transmission involves the "transportation" of electricity from plants to distribution centers using a complex system. Transmission requires: interconnecting and integrating a number of generating plants into a stable, synchronized, alternating current (AC) network; scheduling and dispatching all connected plants to balance the demand and supply of electricity in real time; and managing the system for equipment failures, network constraints, and interaction with other transmission networks.
- The distribution sector is the local delivery system – the relatively low-voltage power lines that bring power to homes and businesses. Electricity distribution relies on a system of wires and transformers along streets and underground to provide electricity to residential, commercial, and industrial consumers. The distribution system involves both the provision of the hardware (*e.g.*, lines, poles, transformers) and a set of retailing functions, such as metering, billing, and various demand management services.

Of the three industry sectors, only electricity generation produces the effluents that are the focus of this rule. The remainder of this profile focuses on the generation sector of the industry.

2.2.2 Prime Movers

Electric power plants use a variety of prime movers to generate electricity. The type of prime mover used at a given plant is determined based on the type of load the plant is designed to serve, the availability of fuels, and energy requirements. Most prime movers use fossil fuels (coal, oil, and natural gas) as an energy source and employ some type of turbine to produce electricity. According to the Department of Energy, the most common prime movers are (U.S. DOE, 2012a):

- Steam Turbine: "Most of the electricity in the United States is produced with steam turbines. In a fossil-fueled steam turbine, the fuel is burned in a boiler to produce steam. The resulting steam then turns the turbine blades that turn the shaft of the generator to produce electricity. In a nuclear-powered steam turbine, the boiler is replaced by a reactor containing a core of nuclear fuel (primarily enriched uranium). Heat produced in the reactor by fission of the uranium is used to make steam. The steam is then passed through the turbine generator to produce electricity, as in the fossil-fueled steam turbine. Steam-turbine generating units are used primarily to serve the base load of electric utilities. Fossil-fueled steam-turbine generating units range in size (nameplate capacity) from 1 megawatt to more than 1,000 megawatts. The size of nuclear-powered steam-turbine generating units in operation today ranges from 75 megawatts to more than 1,400 megawatts."
- Gas Turbine: "In a gas turbine (combustion-turbine) unit, hot gases produced from the combustion of natural gas and distillate oil in a high-pressure combustion chamber are passed directly through the turbine, which spins the generator to produce electricity. Gas turbines are commonly used to serve the peak loads of the electric utility. Gas-turbine units can be installed at a variety of site locations, because their size is generally less than 100 megawatts. Gas-turbine units also have a quick startup time, compared with steam-turbine units. As a result, gas-turbine units are suitable for peak load,

emergency, and reserve-power requirements. The gas turbine, as is typical with peaking units, has a lower efficiency than the steam turbine used for base load power."

- Combined Cycle Turbine: "The efficiency of the gas turbine is increased when coupled with a steam turbine in a combined cycle operation. In this operation, hot gases (which have already been used to spin one turbine generator) are moved to a waste-heat recovery steam boiler where the water is heated to produce steam that, in turn, produces electricity by running a second steam-turbine generator. In this way, two generators produce electricity from one initial fuel input. All or part of the heat required to produce steam may come from the exhaust of the gas turbine. Thus, the supplementary steam-turbine generator may be operated with the waste heat. Combined cycle generating units generally serve intermediate loads."

- Internal Combustion Engine: "These prime movers have one or more cylinders in which the combustion of fuel takes place. The engine, which is connected to the shaft of the generator, provides the mechanical energy to drive the generator to produce electricity. Internal-combustion (or diesel) generators can be easily transported, can be installed upon short notice, and can begin producing electricity nearly at the moment they start. Thus, like gas turbines, they are usually operated during periods of high demand for electricity. They are generally about 5 megawatts in size."

- Hydroelectric Generating Units: "Hydroelectric power is the result of a process in which flowing water is used to spin a turbine connected to a generator. The two basic types of hydroelectric systems are those based on falling water and natural river current. In the first system, water accumulates in reservoirs created by the use of dams. This water then falls through conduits (penstocks) and applies pressure against the turbine blades to drive the generator to produce electricity. In the second system, called a run-of-the-river system, the force of the river current (rather than falling water) applies pressure to the turbine blades to produce electricity. Since run-of-the-river systems do not usually have reservoirs and cannot store substantial quantities of water, power production from this type of system depends on seasonal changes and stream flow. These conventional hydroelectric generating units range in size from less than 1 megawatt to 700 megawatts. Because of their ability to start quickly and make rapid changes in power output, hydroelectric generating units are suitable for serving peak loads and providing immediately available back-up reserve power (spinning reserve), as well as serving base load requirements. Another kind of hydroelectric power generation is the pumped storage hydroelectric system. Pumped storage hydroelectric plants use the same principle for generation of power as the conventional hydroelectric operations based on falling water and river current. However, in a pumped storage operation, low-cost off-peak energy is used to pump water to an upper reservoir where it is stored as potential energy. The water is then released to flow back down through the turbine generator to produce electricity during periods of high demand for electricity."

In addition to prime movers listed above there are a number of other less common prime movers:

- Other Prime Movers: "Other methods of electric power generation, which presently contribute only small amounts to total power production, have potential for expansion. These include geothermal, solar, wind, and biomass (wood, municipal solid waste, agricultural waste, etc.). Geothermal power comes from heat energy buried beneath the surface of the earth. Although most of this heat is at depths beyond current drilling methods, in some areas of the country, magma–the molten matter under the earth's crust from which igneous rock is formed by cooling–flows close enough to the surface of the earth to produce steam. That steam can then be harnessed for use in conventional steam-turbine plants. Solar power is derived from the energy (both light and heat) of the sun. Photovoltaic conversion generates electric power directly from the light of the sun; whereas, solar-thermal electric generators use the heat from the sun to produce steam to drive turbines. Wind power is derived from the conversion of the energy contained in wind into electricity. A wind turbine is similar to a typical wind mill. However, because of the intermittent nature of sunlight and wind, high capacity utilization factors cannot be achieved for these plants. Several electric utilities have incorporated wood and waste (for example, municipal waste, corn cobs, and oats) as energy sources for producing electricity at their power plants. These sources replace fossil fuels in the boiler. The combustion of wood and waste creates steam that is typically used in conventional steam-electric plants."

The type of prime mover is relevant to determining the applicability of the final ELGs to a given plant. As defined in 40 CFR Part 423.10, the final ELGs apply to plants, with discharges resulting from the operation of a generating unit, "whose generation of electricity is the predominant source of revenue or principal reason for operation which results primarily from a process utilizing fossil-type fuel (coal, oil, or gas) or nuclear fuel in conjunction with a thermal cycle employing the steam water system as the thermodynamic medium." [10] The following prime movers (by EIA categories), including both steam turbines and combined cycle technologies, are classified as steam electric:

- Steam Turbine, including coal, gas, oil, waste, nuclear, geothermal, and solar steam (not including combined cycle)
- Combined Cycle Steam Part
- Combined Cycle Combustion Turbine Part
- Combined Cycle Single Shaft (combustion turbine and steam turbine share a single generator)

2.2.3 Ownership

The U.S. electric power industry consists of two broad categories of firms that own and operate electric power plants: utilities and nonutilities. Generally, they can be defined as follows (U.S. DOE, 2012a; U.S. DOE, 2012e):

- <u>Electric utility</u>: An electric utility (utility) is a regulated entity providing electric power within a designated franchised service area. Utilities generally operate in a rate regulation framework in which a government regulatory authority sets prices at which the regulated entity sells generated electricity or other electricity-related services. Electric utilities have traditionally operated in a vertically integrated framework, which included power generation, transmission, and distribution. However, in some instances "generating utilities", which are the focus of this profile within the utility segment, may provide only power generation and transmission services and not provide local distribution services. Other electric utility segments include "transmission utilities," which refers to the regulated owners/operators of transmission systems, and "distribution utilities," which refers to the regulated owners/operators of distribution systems serving retail customers.
- <u>Nonutility</u>: A nonutility is an entity that owns and/or operates electric power generating units but is not subject to rate regulation. Nonutilities generate power for their own use and/or for sale to utilities

[10] As described in Section VIII of the preamble, the final rule revised the definition to clarify that certain facilities, such as generating units owned and operated by industrial facilities in other sectors (*e.g.*, petroleum refineries, pulp and paper mills) that have not traditionally been regulated by the steam electric ELGs, are not within the scope of the ELGs. In addition, the final rule clarifies that certain municipally owned facilities that generate and distribute electricity within a service area (such as distributing electric power to municipal-owned buildings), but use accounting practices that are not commonly thought of as a "sale," are subject to the ELGs. Such facilities have traditionally been regulated by the steam electric ELGs.

and entities operating in a non-regulated pricing environment. A nonutility does not have a designated franchised service area and does not transmit or distribute electricity.

The key distinction between utilities and nonutilities is that utilities generally operate in a rate regulation framework in which a regulatory body sets prices at which the regulated entity sells generated electricity or other electricity-related services, while nonutilities generally operate in a non-regulated pricing environment.

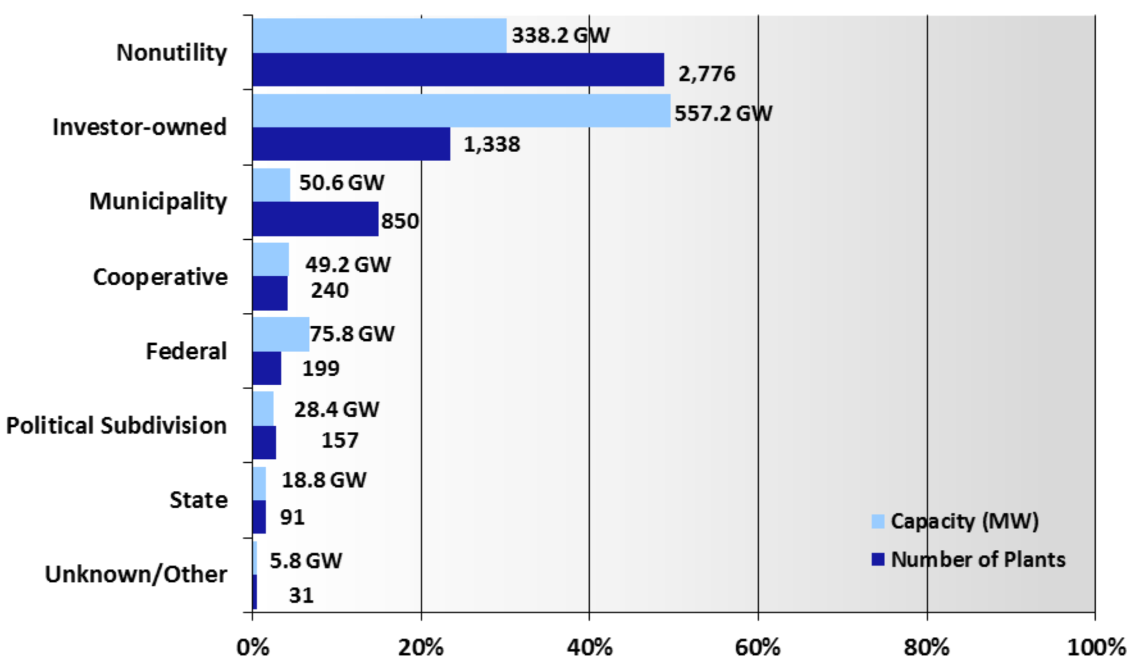
Electric utilities can be further divided into three major ownership categories: investor-owned utilities, publicly owned utilities, and rural electric cooperatives. Each category is discussed below (U.S. DOE, 2012a; U.S. DOE, 2012e):

- Investor-owned utilities: Investor-owned utilities (IOUs) are for-profit, privately-owned businesses. IOUs are regulated by State and sometimes federal governments, which in turn approve rates that allow a fair rate of return on investment. These utilities either distribute profits to stockholders as dividends or reinvest the profits. Most IOUs engage in generation, transmission, and distribution. Historically, IOUs have been most successful in serving large, consolidated markets where economies of scale afford the lowest rates. IOUs are granted service monopolies in specified geographic areas. As a condition for granting of the service monopoly, IOUs are required to serve all customers giving them access to service under similar conditions and charging comparable prices to similar classifications of consumers. In 2009, IOUs operated 2,776 plants, which accounted for approximately 50 percent of all U.S. electric generating capacity.
- Publicly owned utilities: These are nonprofit, government agencies established to provide service to their communities and nearby consumers at cost, returning excess funds to consumers in the form of community contributions, increased economies and efficiencies in operations, and reduced rates. Publicly-owned electric utilities can be federal power agencies, State authorities, municipalities, and other political subdivisions (*e.g.*, public power districts and irrigation projects). Excess funds or "profits" from the operation of these utilities are put toward reducing rates, increasing plant efficiency and capacity, and funding community programs and local government budgets. Smaller municipal utilities, which make up the majority municipal utilities, are nongenerators engaging solely in the purchase of wholesale electricity for resale and distribution. Larger municipal utilities, as well as State and federal utilities, usually generate, transmit, and distribute electricity. In general, publicly-owned utilities have access to tax-free financing and do not pay certain taxes or dividends, giving them some cost advantages over IOUs. In 2009, the federal government operated 199 plants (accounting for 7 percent of total U.S. electric generation capacity), States owned 91 plants (2 percent of U.S. capacity), and municipalities owned 850 plants (4 percent of U.S. capacity).
- Rural electric cooperatives: Cooperative electric utilities ("coops") are member-owned entities created to provide electricity to those members. These utilities provide electricity to rural sparsely populated areas, which historically have been viewed as uneconomical operations for IOUs. Electric cooperatives operate at cost and, as nonprofit entities, are exempt from federal income tax. Cooperatives are incorporated under State laws and are usually directed by an elected board of directors. The Rural Utilities Service (formerly the Rural Electrification Administration), the National Rural Utilities Cooperative Finance Corporation, the Federal Financing Bank, and the Bank for Cooperatives are important sources of debt financing for cooperatives. In 2009, rural electric cooperatives operated 240 generating plants and accounted for approximately 4 percent of all U.S. electric generation capacity.

The type of entities owning and operating electric power plants is an important consideration for assessing the impact of the final ELGs on steam electric power plants and electricity consumers, as it is one of the factors affecting the recovery of any increases in production costs resulting from compliance with the final ELGs through higher electricity rates. However, ownership type is not the only determining factor and cannot be used as the sole basis for any definite conclusions regarding compliance cost recovery at steam electric power plants. A likely more important factor is the regulatory environment in the state where a steam electric power plant is located (discussed later in this chapter). Other factors include 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.

Figure 2-1 reports the number of generating plants and their capacity in 2012, by type of ownership. To determine the ownership type for each of these plants, EPA relied on the information reported in the industry survey, the 2006 EIA-860, 2012 EIA-860, and 2012 EIA-861 databases, and additional research (U.S. DOE, 2006; U.S. DOE, 2012b; U.S. DOE, 2012c; U.S. EPA, 2010a).[11] The horizontal axis also presents the percentage of the U.S. total that each type represents. This figure is based on data for all electric power generating plants that have at least one non-retired unit and that submitted Form EIA-860 for 2012. The chart shows that nonutilities account for the largest percentage of plants (54 percent) but represent only 32 percent of total U.S. generating capacity. Investor-owned utilities operate the second largest percentage of plants at 21 percent and account for 48 percent of total U.S. capacity.

Figure 2-1: Distribution of Plants and Nameplate Capacity by Ownership Type, 2012



Source: U.S. DOE, 2006; U.S. DOE, 2012b; U.S. DOE, 2012c; U.S. EPA, 2010a

[11] Prior to 2007, ownership information at the utility/operator level was reported in the EIA-860 database; this information was reported for more plants than in the EIA-861 database, which covers regulated plants only.

2.3 Domestic Production

This section presents an overview of generating capacity and electricity generation. *Section 2.3.1* provides data on capacity, and *Section 2.3.2* provides data on generation. *Section 2.3.3* gives an overview of the geographic distribution of generation plants and capacity.

2.3.1 Generating Capacity

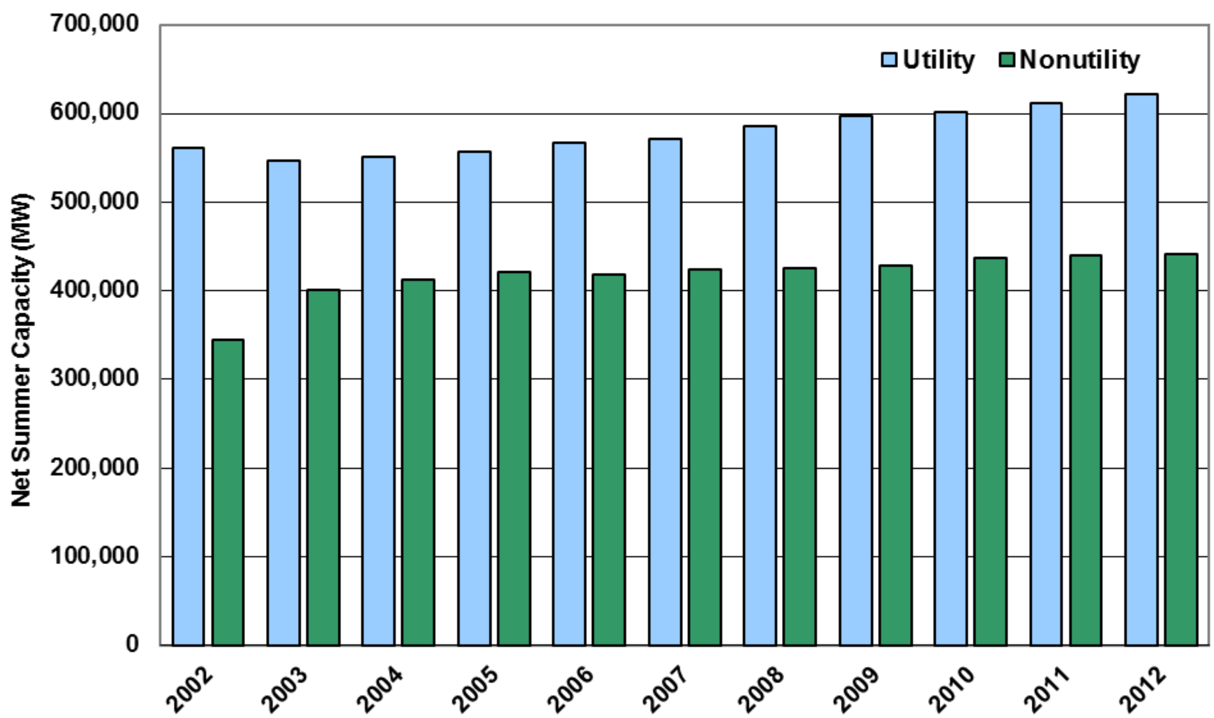
The rating of a generating unit, expressed in megawatts (MW), is a measure of its ability to produce electricity. Capacity and capability are the two most common measures. *Nameplate capacity*, which is generally greater than a generating unit's net summer or winter capacity, is the maximum rated (*i.e.*, full-load) output of a generating unit under specified conditions, as designated by the manufacturer. Net summer capacity is the maximum output that a generating unit can supply to *system load* at the time of *summer* peak demand;[12] it reflects a reduction in capacity due to electricity use for station service or auxiliaries and relative efficiency loss due to warmer cooling water or air temperature for combustion turbines. *Net winter capacity* is the maximum output that a generating unit can supply to *system load* at the time of *winter* peak demand;[13] it also reflects a reduction in capacity due to electricity use for station service or auxiliaries. (U.S. DOE, 2012a).

In 2012, utilities owned and operated the majority of *net summer capacity* (59 percent) in the United States, with nonutilities owning the remaining 42 percent (numbers do not add to 100 percent due to rounding). Nonutility ownership of net summer capacity increased substantially in the 2000s, following the passage of state legislation aimed at increasing competition in the electric power industry. Nonutility ownership of net summer capacity increased by 28 percent between 2002 and 2012, compared with an increase in utility ownership of net summer capacity of 11 percent over the same time period, as traditional regulated utilities sold generating capacity to nonutility power producers to meet state-based deregulation requirements. Overall, total net summer capacity increased during this period, from approximately 905,302 MW in 2002 to 1,063,033 MW in 2012 (see *Figure 2-2*). Total net summer capacity for 2013 is not included in *Figure 2-2* but is similar to that in 2012, at 1,060,064 MW, and shows a slightly lower fraction of the capacity owned by utilities (58 percent) and nonutilities owning a correspondingly slightly higher share of the net summer capacity (U.S. DOE, 2015).

[12] In the United States, summer peak is the period of June 1 through September 30.

[13] In the United States, winter peak is the period of December 1 through February 28(29).

Figure 2-2: Net Summer Capacity (MW), 2002 to 2012



Source: U.S. DOE, 2013c

2.3.2 Electricity Generation

The production of electricity is referred to as generation and is measured in units of produced energy such as kilowatt-hours (kWh) or megawatt-hours (MWh). Generation can be measured by gross generation, net generation, or electricity available to consumers. *Gross generation* is the total amount of electricity produced by an electric power plant. *Net generation* is the amount of gross generation *less* electricity consumed by the electricity generating plant for operation of the power generating station, including, for example, lights at the plant, operation of fuel supply systems, and electricity required for pumping at pumped-storage plants. In other words, *net generation* is the amount of electricity available to the transmission system beyond that needed to operate plant equipment (U.S. DOE, 2012e).

As presented in *Table 2-1*, total net electricity generation in the United States for 2012 was 4,048 TWh.[14] In 2012, coal accounted for the largest share of total electricity generation (37 percent), despite a 21 percent decline over the 11-year period of 2002 through 2012. In terms of the share of the total generation, coal was followed by natural gas (30 percent) and nuclear power (19 percent). Other energy sources accounted for comparatively smaller shares of total generation, with hydropower representing 7 percent; renewable energy, 5 percent; and petroleum, 1 percent (see *Figure 2-3)*. The year 2013 saw a 0.4 percent increase in net

[14] One terawatt-hour is 10^{12} watt-hours.

electricity generation relative to 2012, to a total of 4,065 TWh, with coal representing a larger share (39 percent) of generation than in 2012 (U.S. DOE, 2015).

In 2012, utility-owned plants accounted for 58 percent of total electricity generation, with nonutility-owned plants accounting for the remaining 42 percent. The distribution of generation between utilities and nonutilities varied considerably by energy source, with utilities accounting for larger shares of coal-, hydropower-, petroleum-, and nuclear power-fueled electricity generation than nonutilities.

As presented in *Table 2-1*, over the 11-year period of 2002 through 2012, total net generation increased by approximately 5 percent. This growth was driven by increases in natural gas- and renewables-fueled electricity generation and, to a lesser extent, by hydropower electricity generation. During the same time, coal-, nuclear-, and petroleum- fueled electricity generation declined, with petroleum recording the largest percent decline of 76 percent. Data for 2013 show a break in the trend of declining coal generation with a 4 percent increase relative to 2012, to 1,581 TWh (U.S. DOE, 2015).

Between 2002 and 2012, the amount of electricity generated by utilities declined by 8 percent while that generated by nonutilities rose by 31 percent. Comparing 2002 and 2012 values, across all fuel-source categories, utilities generated a larger share of their electricity using natural gas (a 120 percent increase) and renewables (an 807 percent increase) even as their overall generation declined. For nonutilities, the largest percent increase in electricity generation (150 percent) occurred for renewables, followed by natural gas and nuclear power.

Table 2-1: Net Generation by Energy Source and Ownership Type, 2002 to 2012 (TWh)

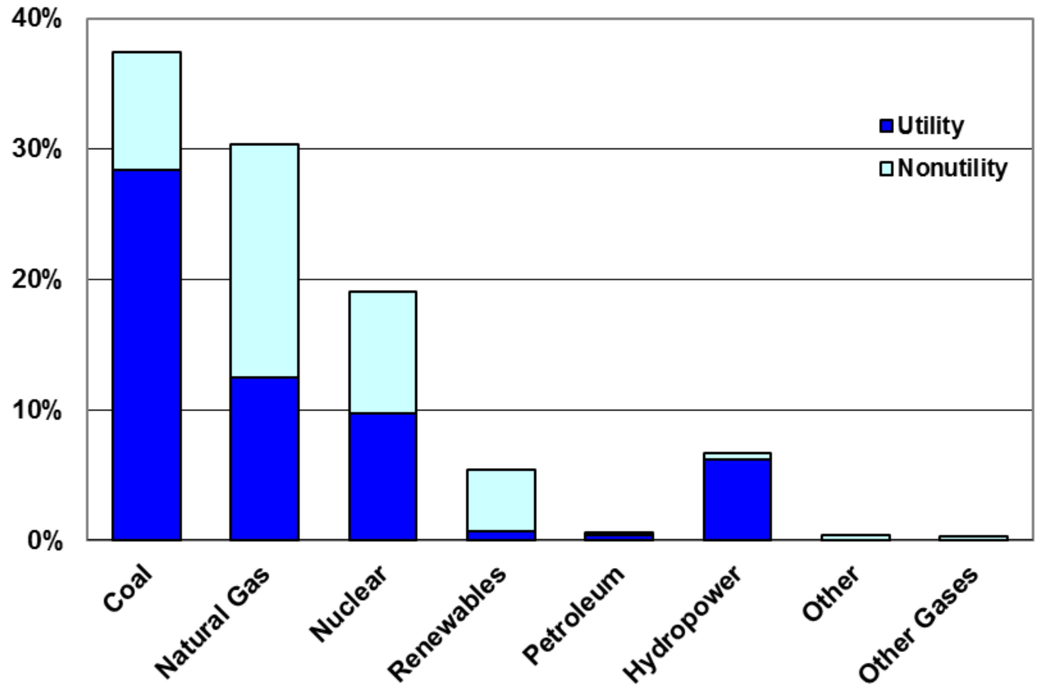
	Utilities			Nonutilities			Total		
Energy Source	**2002**	**2012**	**% Change**	**2002**	**2012**	**% Change**	**2002**	**2012**	**% Change**
Coal	1,515	1,146	-24.3%	418	368	-12.2%	1,933	1,514	-21.7%
Hydropower	235	249	5.9%	21	23	8.9%	256	271	6.1%
Nuclear	507	395	-22.2%	273	375	37.3%	780	769	-1.4%
Petroleum	59	16	-73.7%	35	8	-78.5%	95	23	-75.5%
Natural Gas	230	505	119.9%	461	721	56.3%	691	1,226	77.4%
Other Gases	0	0	-100.0%	11	12	5.7%	11	12	3.8%
Renewables[a]	3	28	807.0%	76	190	150.3%	79	218	176.0%
Other[b]	0	1	25.6%	13	13	1.1%	14	14	1.9%
Total	**2,549**	**2,339**	**-8.2%**	**1,309**	**1,709**	**30.5%**	**3,858**	**4,048**	**4.9%**

a. Renewables include wind, solar thermal and photovoltaic, wood and wood derived fuels, geothermal, and other biomass.

b. Other includes non-biogenic municipal solid waste, batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, tire-derived fuels and miscellaneous technologies.

Source: U.S. DOE, 2013c

Figure 2-3: Percent of Electricity Generation by Primary Fuel Source for Each Plant Ownership Type, 2012



Source: U.S. DOE, 2013c

2.3.3 Geographic Distribution

Electricity cannot be stored or easily transported over long distances. As a result, the geographic distribution of power plants is of primary importance to ensure a reliable supply of electricity to all customers. 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. This system contains six of the NERC regions defined below (the FRCC – Florida Reliability Coordinating Council, the MRO – Midwest Reliability Organization, the NPCC – Northeast Power Coordinating Council (U.S. component), the RFC – Reliability First Corporation, the SERC – Southeastern Electric Reliability Council, and the SPP – Southwest Power Pool).

- The *Western Interconnected System* covers nearly all of areas west of the Rocky Mountains, including the Southwest. The only NERC region within this system is the WECC – Western Energy Coordinating Council (U.S. component).

- The *Texas Interconnected System*, the smallest of the three major networks, covers the majority of Texas. The only NERC region within this system is Texas Regional Entity (TRE).

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.

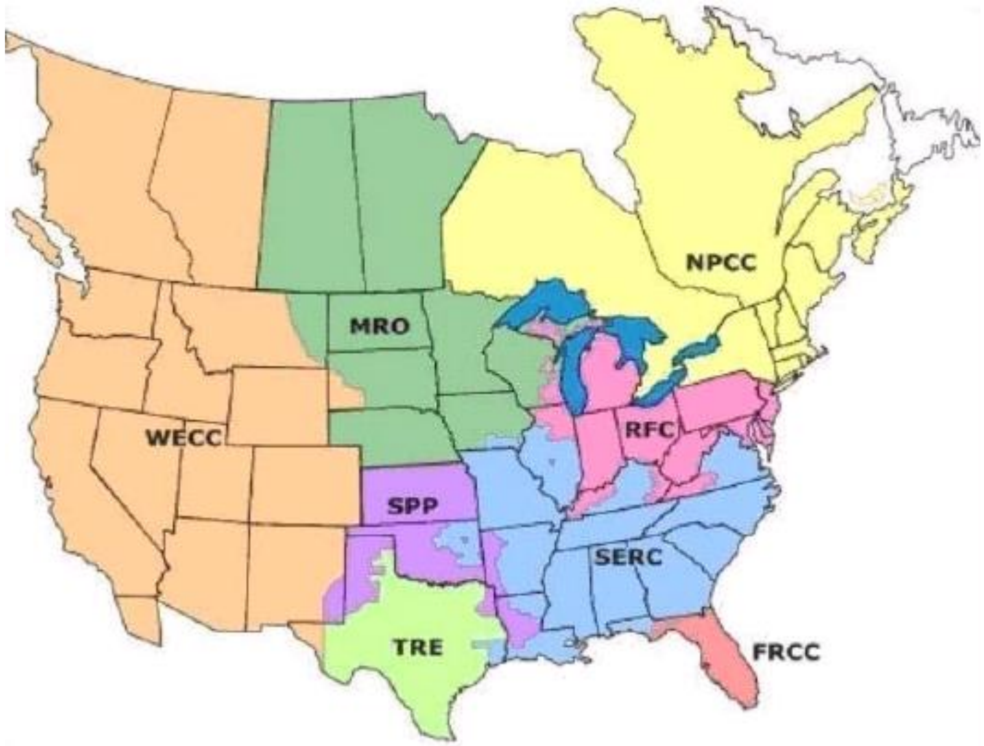
Reliability refers to the ability of power systems to meet the demands of consumers at any given time. Efforts to enhance reliability reduce the chances of power outages. The North American Electric Reliability Corporation (NERC) is responsible for the overall reliability, planning, and coordination of the power grids. NERC was formed as a voluntary organization in 1968 by electric utilities, following a 1965 blackout in the Northeast. An independent, not-for-profit organization, it received regulatory authority in 2006 for ensuring electric reliability in the United States, under the oversight of FERC. NERC is organized into eight regional organizations that cover the 48 contiguous States, and two affiliated councils that cover Hawaii, part of Alaska, and portions of Canada and Mexico.[15] These regional organizations are responsible for the overall coordination of bulk power policies that affect their regions' reliability and quality of service. As discussed above, 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 2-4* provides a map of the 2012 NERC regions, which include:[16]

- ASCC – Alaska Systems Coordinating Council
- FRCC – Florida Reliability Coordinating Council
- HICC – Hawaii Coordinating Council
- MRO – Midwest Reliability Organization
- NPCC – Northeast Power Coordinating Council (U.S.)
- RFC – Reliability First Corporation
- SERC – Southeastern Electric Reliability Council
- SPP – Southwest Power Pool
- TRE – Texas Regional Entity
- WECC – Western Energy Coordinating Council (U.S.)

[15] 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.

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

Figure 2-4: 2012 North American Electric Reliability Corporation (NERC) Regions



a The ASCC and HICC regions are not shown.

Source: U.S. DOE, 2012f.

Table 2-2 shows the distribution of all existing plants and total capacity by NERC region. As reported in *Table 2-2,* 1,506 plants (approximately 27 percent of all existing plants in the United States) are located in WECC. However, these plants account for only approximately 18 percent of total national capacity. Conversely, only 16 percent of existing plants are located in SERC, yet these plants account for approximately 26 percent of total national capacity.

The final ELGs are expected to potentially affect plants located in different NERC regions differently. Because of variations in the economic and operational characteristics of steam electric power plants across NERC regions, and in the baseline economic characteristics of the NERC regions themselves, together with market segmentation due to limited interconnectedness among NERC regions, the final rule would have a different effect on profitability, electricity prices, and other impact measures across NERC regions.

Table 2-2: Distribution of Existing Plants and Total Capacity by NERC Region, 2012

	Plants		Capacity	
NERC Region	**Number**	**% of Total**	**Total MW**	**% of Total**
ASCC	130	2.1%	2,322	0.2%
FRCC	131	2.1%	65,508	6.1%
HICC	43	0.7%	2,982	0.3%
MRO	813	13.2%	65,820	6.2%
NPCC	795	12.9%	81,610	7.6%
RFC	1,099	17.8%	251,838	23.6%
SERC	979	15.8%	302,583	28.3%

Table 2-2: Distribution of Existing Plants and Total Capacity by NERC Region, 2012

NERC Region	Plants		Capacity	
	Number	% of Total	Total MW	% of Total
SPP	343	5.6%	74,839	7.0%
TRE	282	4.4%	99,298	8.5%
WECC	1,844	29.9%	221,516	20.7%
TOTAL	**6,459**	**100%**	**1,168,315**	**100%**

Source: U.S. DOE, 2012b

2.4 Steam Electric Power Plants

The final ELGs establish new requirements for plants that are subject to the previously established ELGs for the Steam Electric Power Generating Point Source Category. The ELGs apply to discharges resulting from the operation of a generating unit by an establishment that is "primarily engaged in the generation of electricity for distribution and/or sale, which results primarily from a process utilizing fossil-type fuels (coal, petroleum coke, oil, gas) or nuclear fuel in conjunction with a thermal cycle employing the steam water system as the thermodynamic medium." Based on the data collected through the industry survey, EPA identified 1,080 steam electric power plants.[17] Subsequent review of the data reveals that some of the plants EPA surveyed in 2010 have since ceased operating. However, the retired generating capacity has been offset by new capacity at other steam electric power plants that were not included in the 2010 industry survey, so that the universe of 1,080 steam electric power plants derived from the survey data is still a reasonable representation of the Steam Electric Power Generating industry. Section 4.5 of the TDD describes the changes in to the steam electric industry population since the 2009 industry survey, including retirements and fuel conversions (U.S. EPA, 2015c).

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

- **Ownership type**: *Section 2.4.1* reviews the distribution of steam electric power plants and their parent-entities across ownership categories.
- **Parent-entity size**: *Section 2.4.2* assesses the distribution of parent-entities across ownership categories by parent-entity size for parent-entities owning steam electric power plants.
- **Plant size**: *Section 2.4.3* reviews the size of steam electric power plants based on generating capacity.
- **Geographic distribution**: *Section 2.4.4* reports the geographic distribution of steam electric power plants across NERC regions.

2.4.1 Ownership Type

As discussed in *Section 2.2.3*, 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. This classification is important

[17] The industry survey gathered information from a sample of 733 plants, of which 681 respondents are steam electric plants. After removing plants that did not operate steam electric power generating units in 2009 and applying sample weights, EPA estimated at 1,080 the total number of existing steam electric plants to which 40 CFR part 423 apply. For more information on the survey and on the development and application of sample weights, see *Technical Development Document* (*TDD*).

because EPA has to assess the impact of the final ELGs on State, local, and tribal governments in accordance with the Unfunded Mandates Reform Act (UMRA) of 1995 (see *Chapter 9: Unfunded Mandates Reform Act (UMRA) Analysis*).[18]

Table 2-3 reports the number of parent entities, plants, and capacity by ownership type for the total industry and for the subset of 1,080 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*). Overall, EPA estimates that steam electric power plants account for between 8 percent (lower bound) and 16 percent (upper bound) of all parent entities, 19 percent of all electric power plants, and 67 percent of total electric power sector capacity.[19,20] The majority of steam electric power plants (63 percent of all steam electric power plants) are owned by investor-owned utilities, while nonutilities make up the second largest category (14 percent of all steam electric power plants). In terms of steam electric capacity, investor-owned utilities account for the largest share (71 percent) of total steam electric capacity.

Table 2-3: Existing Steam Electric Power Plants, Their Parent Entities, and Capacity by Ownership Type, 2009

	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	29	11.9%	49	9.6%	63	5.9%	36,696	4.7%
Federal	2	0.8%	4	0.8%	15	1.4%	31,167	4.0%
Investor-owned	97	39.9%	244	48.1%	681	63.0%	557,134	71.0%
Municipality	65	26.7%	101	20.0%	122	11.3%	40,024	5.1%
Nonutility	36	14.8%	77	15.1%	153	14.2%	88,642	11.3%
Other Political Subdivisions	12	4.9%	30	6.0%	41	3.8%	26,292	3.3%
State	2	0.8%	2	0.4%	5	0.5%	5,017	0.6%
Steam Electric Total	**243**	**100.0%**	**507**	**100.0%**	**1,080**	**100.0%**	**784,972**	**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 industry survey and additional research of publically 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 counts and capacity were calculated on a sample-weighted basis. For details on sample weights, see *TDD*.

Source: U.S. EPA Analysis, 2015; U.S. DOE, 2006; U.S. DOE, 2012b; U.S. DOE, 2012c; U.S. EPA, 2010a

[18] As discussed earlier in this chapter, while ownership type may affect the ability of steam electric plants and their parent entities to recover an increase in electricity generation costs due to the final ELG, it is not a sole or a deciding factor.

[19] EPA estimates that there are 5,682 electric power plants in the United States; these plants are owned by 3,150 entities and account for 1,168,315 MW of total generating capacity.

[20] The number of parent entities estimated for the electric power industry as a whole is the number of utilities/operators reported as owning existing electric power plants in the 2012 EIA-860 database (U.S. DOE, 2012b).

2.4.2 Ownership Type

EPA estimates that between 34 percent and 40 percent of entities owning steam electric power plants are small, compared to 43 percent estimated for the electric power industry as a whole (*Table 2-4*), according to Small Business Administration (SBA) (2014) business size criteria.[21,22] Small entities owning steam electric power plants represent between 9 percent and 15 percent of all small entities in the electric power industry.

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 category (17 percent), while small municipalities make up the largest share of small entities (57 percent). Under the upper bound estimate, again, small entities make up the lowest share of other political subdivision entities (14 percent), while small entities make up the largest share of all nonutilities (47 percent).

EPA estimates that out of 1,080 steam electric power plants, 231 (21 percent) are owned by small entities (*Table 2-5*). Investor-owned utilities own the largest share of steam electric power plants owned by small entities, at 41 percent, while cooperatives, investor-owned nonutilities, and other political subdivisions own the remaining 59 percent. By definition, States and the federal government are considered large entities. 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 2-4: 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	26	3	29	89.7%	46	3	49	100.0 %
Federal	0	2	2	0.0%	0	4	4	0.0%
Investor-owned	28	69	97	28.9%	66	178	244	27.1%
Municipality	36	29	65	55.4%	43	59	101	42.1%
Nonutility	19	17	36	52.8%	35	41	77	46.1%
Other Political Subdivision	1	11	12	8.3%	1	29	30	3.3%
State	0	2	2	0.0%	0	2	2	0.0%
Total	**110**	**133**	**243**	**45.3%**	**191**	**316**	**507**	**37.6%**

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, 2015; U.S. DOE, 2006; U.S. DOE, 2012b; U.S. DOE, 2012c; U.S. DOE, 2012d; U.S. EPA, 2010a

[21] EPA determined entity size for industry-wide parent entities in two steps. The Agency first used utility/operator-level electricity sales data from the 2012 EIA-861 database (U.S. DOE, 2012c) and, if sales data were not available, electricity net generation data from the 2012 EIA-906/920/923 database (U.S. DOE, 2012d) to determine utility/operator size using the 4,000,000 MWh SBA size criterion. To account for the fact that (1) utility/operator may not be the highest-level domestic parent and (2) according to SBA, size determination for entities of certain ownership types should be based on criteria other than total electric output, EPA then adjusted counts of small utilities/operators estimated in the first step. The Agency made that adjustment based on the observed relationship between electric output-based size determination and size determination based on the appropriate SBA criterion for the steam electric universe.

[22] EPA estimates that 1,069 out of the total 2,657 entities (40 percent) that own electric power plants are small.

Table 2-5: 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	55	8	63	87.4%
Federal	0	15	15	0.0%
Investor-owned	95	586	681	14.0%
Municipality	46	76	122	37.7%
Nonutility	34	119	153	22.1%
Other Political Subdivisions	1	40	41	2.5%
State	0	5	5	0.0%
Total	**231**	**849**	**1,080**	**21.4%**

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

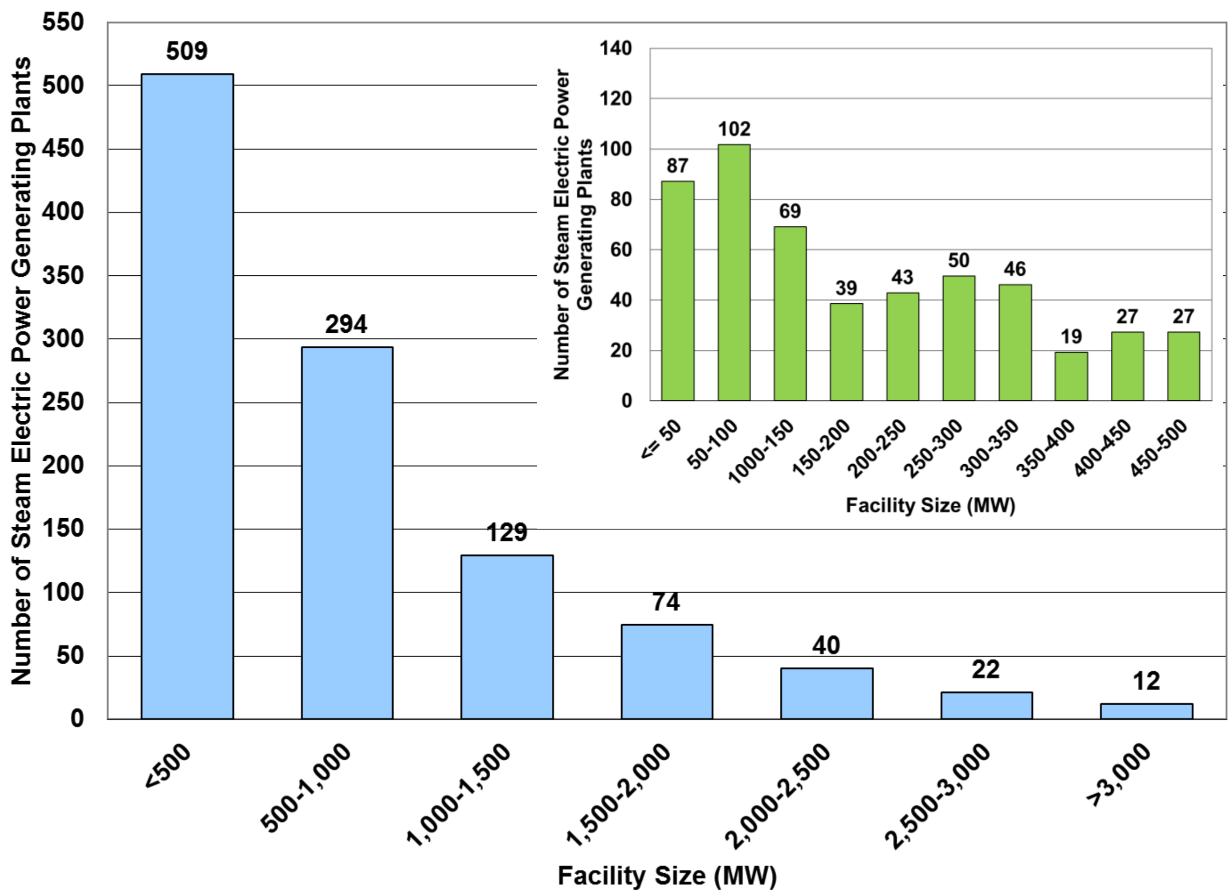
b. Plant counts are sample-weighted estimates.

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, 2015; U.S. DOE, 2012b; U.S. DOE, 2012c; U.S. EPA, 2010a

2.4.3 Plant Size

EPA also assessed the size of steam electric power plants in terms of their generating capacity. Plant size is relevant because of its importance in meeting electricity demand and reliability needs. The majority of steam electric power plants (74 percent) have a capacity of 1,000 MW or less, while only a few plants (3 percent) have a capacity greater than 2,500 MW (*Figure 2-5*). As shown in the insert in *Figure 2-5*, which provides detailed counts for the subset of steam electric power plants with generating capacity of 500 MW or less, 87 steam electric power plants had a capacity of 50 MW or less.

Figure 2-5: Number of Steam Electric Power Plants by Size (in MW), 2009[a,b]



Source: U.S. EPA Analysis, 2015; U.S. DOE, 2012b; U.S. DOE, 2012c; U.S. EPA, 2010a

2.4.4 Geographic Distribution of Steam Electric Power Plants

To assess the potential reliability impact of the final ELGs, 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 concentrated in the RFC, SERC, and WECC regions (21 percent, 20 percent, and 18 percent, respectively); these three regions also account for a majority of the steam electric capacity in the United States (24 percent, 27 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%	58	0.0%
FRCC	54	5.0%	61,701	7.9%
HICC	12	1.1%	1,418	0.2%
MRO	87	8.0%	38,494	4.9%
NPCC	104	9.6%	37,600	4.8%

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
RFC	231	21.4%	186,430	23.7%
SERC	218	20.1%	209,033	26.6%
SPP	92	8.6%	66,015	8.4%
TRE	85	7.9%	66,873	8.5%
WECC	194	18.0%	117,349	14.9%
TOTAL	**1,080**	**100.0%**	**784,972**	**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, 2015; U.S. DOE, 2012b; U.S. EPA,2010a

2.5 Industry Trends

While several factors, such as shifts in natural gas production have had a significant effect on the electric power industry in recent years, deregulation and several new environmental regulations and programs, also affected the industry. *Section 2.5.1* discusses the current status of industry deregulation, *Section 2.5.2* discusses renewable portfolio standards, and *Sections 2.5.3* through *0* discuss recent environmental regulations that have affected and/or will affect the electric power industry.

2.5.1 Current Status of Industry Deregulation

The electric power industry has evolved from a highly regulated industry with traditionally-structured electric utilities to a less regulated, more competitive industry. Several key pieces of Federal legislation have made the changes in the industry's structure possible. The industry has traditionally been regulated based on the premise that the supply of electricity is a natural monopoly, where a single supplier could provide electric services at a lower total cost than could be provided by several competing suppliers. During the last two decades, the relationship between electricity consumers and suppliers has undergone substantial change, as governments and regulatory agencies recognized that electricity generation does not necessarily meet the definition of a natural monopoly. As a result, substantial steps have been undertaken to promote competition in generation, thereby achieving better electricity production efficiency among electricity generators, while recognizing that the delivery of electricity via transmission and distribution systems does remain within the definition of a natural monopoly. A key step in this effort is the required unbundling of the traditional vertically integrated electric power business, with the electricity generation business (and therefore the electricity generating assets) being separated from the electricity transmission and distribution business. Electricity restructuring has two essential aspects: wholesale access and retail access. *Wholesale access* refers to the ability of electric power generating entities – utilities and independent power producers – to access *transmission systems* to compete for wholesale markets, *i.e.*, distribution utilities and independent marketers buying and selling electricity. *Retail access* refers to the ability of marketers and retailing businesses of utilities to obtain access to *distribution systems* to sell electricity to end-use consumers, thereby introducing consumer choice of electricity supplier (or retail choice).

The initial actions promoting competition in the wholesale electric power markets began with the Public Utility Regulatory Policies Act of 1978 (PURPA), which established business terms by which certain nonutility electricity-generators – "qualifying plants" or QFs – could sell electricity to utilities. Later, the Energy Policy Act of 1992 (EPACT) made it easier for nonutilities to enter the wholesale electricity market by creating a new category of nonutility power producers – exempt wholesale generators or EWGs – which were exempt from the Public Utility Holding Company Act of 1935 (PUHCA) regulation (EEMCTF, 2007).[23] In 1996, the Federal Energy Regulatory Commission (FERC) issued Order 888, promoting wholesale electric competition, by ensuring non-discriminatory open access transmission service, and, in some states, the introduction of retail choice. Order 888 also established guidelines for the formation of independent system operators (ISOs), independent, federally regulated entities established to coordinate regional transmission in a non-discriminatory manner.

Nearly a decade later, the Energy Policy Act of 2005 (EPAct 2005) repealed the original PUHCA of 1935, while enacting provisions to encourage investment in energy infrastructure and transfer certain consumer protection oversight authorities from the Security and Exchange Commission (SEC) to FERC and the states. Specifically, EPAct 2005 enacted a *new* PUHCA (PUHCA of 2005), which gives FERC, as opposed to SEC, jurisdiction over holding companies. EPAct 2005 also modified PURPA of 1978, removing some pricing requirements that had resulted in consumers paying above-market prices for some electricity. In addition, EPAct 2005 created the Electric Reliability Organization (ERO), now certified as the NERC, to enforce mandatory electric reliability rules on all users, owners, and operators of the transmission systems (FERC, 2006).

Key Changes in the Electric Power Industry Structure

Industry deregulation has already changed and continues to change the structure of the electric power industry. Some of the key changes include:

- Provision of services: Under the traditional regulatory system, the generation, transmission, and distribution of electric power were handled by vertically-integrated utilities. Since the mid-1990s, Federal and State policies have led to increased competition in the generation sector of the industry. Increased competition has resulted in a separation of power generation, transmission, and retail distribution services. Utilities that provide transmission and distribution services continue to be regulated and are required to divest their generation assets. In the deregulated framework, entities that generate electricity are no longer subject to rate regulation and do not operate in protected franchise markets.
- Relationship between electricity providers and consumers: Under traditional regulation, utilities were granted a geographic franchise area and provided electric service to all customers in that area at a rate approved by the regulatory commission. A consumer’s electric supply choice was limited to the utility franchised to serve their area. Similarly, electricity suppliers were not free to pursue customers outside their designated service territories. Although most consumers continue to receive power through their local distribution company (LDC), retail competition has allowed some consumers to select the company that generates the electricity they purchase.
- Electricity prices: Under the traditional system, State and Federal authorities regulated many aspects of utilities’ business operations, including, in particular, their prices. Electricity prices were determined administratively for each utility, based on the cost of producing and delivering power to customers and a reasonable rate of return on invested capital (*i.e.*, under the cost-of-service

[23] PUHCA of 1935 was passed by the United States Congress to facilitate regulation of electric utilities, by either limiting their operations to a single state, and thus subjecting them to effective state regulation, or forcing divestitures so that each company became a single integrated system serving a limited geographic area. In addition, PUHCA of 1935 required holding companies to obtain permission from the Securities and Exchange Commission (SEC) prior to engaging in a non-utility business and further required that such businesses be kept separate from the regulated businesses.

framework). As a result of deregulation, competitive market forces set prices for generated electricity. Buyers and sellers of power negotiate through power pools or one-on-one to set the price of electricity. As in any competitive market, prices reflect the interaction of supply and demand for electricity. During most time periods, the price of electricity in a given competitive wholesale electricity market (*e.g.*, an integrated dispatch region) is set by the generating unit with the highest energy production cost that is dispatched to meet spot market electricity demand – *i.e.*, the unit with the highest production cost determines the "marginal cost" of production and therefore the short-run energy price (Beamon, 1998).

New Industry Participants

As discussed above, PURPA and EPAct set business terms by which nonutility generators – QFs and EWGs, respectively – could enter the wholesale power market. Under PURPA, utilities are required to buy power that is produced by QFs (usually cogeneration or renewable energy) in their service area at a price equal to the avoided production cost of a buying utility. EPAct did not require utilities to purchase power from EWGs. Instead, EPAct gave FERC the authority to order utilities to provide access to their transmission systems on a case-by-case basis. However, access to the systems proved to be slow and burdensome. In response, FERC issued Order 888, which provides open access to the transmission systems by utilities that have filed open-access transmission tariffs (OATTs) by a specific deadline. Furthermore, in 1999, FERC issued Order 2000, calling for the development of Regional Transmission Organizations (RTOs), which independently control and operate the transmission systems (EEMCTF, 2007).[24]

State Activities

The current status of electricity restructuring varies across states. Out of 50 states, 22 had initiated efforts to design restructured electricity markets and pass enabling legislation. However, eight of these 22 states – Arizona, Arkansas, California, Montana, Nevada, New Mexico, Oregon, and Virginia – experienced difficulties during the transition to a competitive electricity market, such as lack of competition for residential customers and substantial rate increases that have occurred or are anticipated to occur; consequently, seven of these eight states suspended the restructuring process. As of September 2010, only 15 states[25] and the District of Columbia were operating with some degree of competitive wholesale and retail electricity markets, in which some or all of the energy portion of the retail electricity price is determined in a deregulated market. The remaining 28 states have not introduced any electricity restructuring legislation. The 35 states with regulated electricity market host 3,751 plants (66 percent of all electric power generating plants in the United States) and 730 GW of generating capacity (64 percent of total generating capacity in the United States) (U.S. DOE, 2012b; 2010). *Figure 2-6* provides a national map of the status of electricity restructuring.

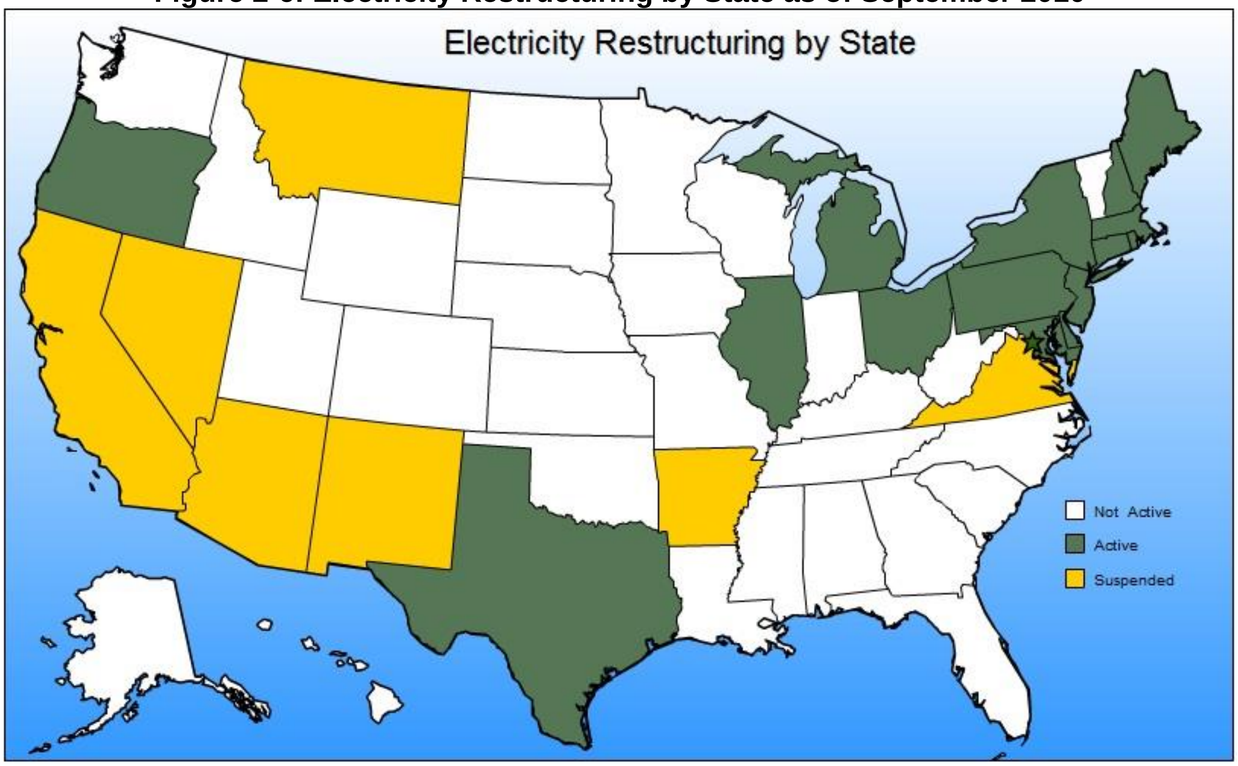
The state of restructuring of the electric power industry is an important factor to consider when assessing the impact of the final ELGs on steam electric power plants and electricity consumers, as discussed in *Chapter 4: Cost and Economic Impact Screening Analyses* and *Chapter 7:Assessment of Potential Electricity Price Effects*. In particular, the degree of competition affects, although not solely, the ability of steam electric power plants to pass cost increases to consumers via electricity rate increases, and consequently, affects their profitability and business viability. Most steam electric power plants (672 out of 1,080 or 62 percent) are located in states with regulated electricity generation markets; these plants account for 65 percent of total generating capacity (514 GW out of 785 GW) and total generation (2,249 TWh out of 3,463 TWh) at steam

[24] RTO is similar to ISO, with the main difference being the ability of RTO to control and monitor the electric power transmission system over a wider area across state borders.

[25] These 15 states are: Connecticut, Delaware, Illinois, Maine, Maryland, Massachusetts, Michigan, New Hampshire, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, Texas, Oregon.

electric power plants. EPA judges that these plants may be able to recover increases in their production costs resulting from compliance with the proposed ELGs through higher electricity rates, subject to approval by utility regulatory authorities and depending on the business operation model of their owner or operator, the ownership structure of the plant itself, and the role of market mechanisms used to sell electricity.[26] The other 408 steam electric power plants (38 percent) are located in states where electricity generation is deregulated and cost recovery is less certain; these plants account for approximately 271 GW of total generating capacity (35 percent) and 1,214 TWh of total generation (35 percent) at steam electric power plants (U.S. DOE, 2012b).[27,28]

Figure 2-6: Electricity Restructuring by State as of September 2010



Source: U.S. DOE, 2010

2.5.2 Renewable Portfolio Standards

In many states, Renewable Portfolio Standards (RPS) require electric utilities to generate a certain percentage of power from renewable sources. States have increasingly adopted RPS since the late 1990s: as of September

[26] As discussed earlier in this chapter, while 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 as the sole basis for cost-pass-through determination.

[27] Plant counts and capacity and generation values are sample-weighted estimates. These sample weights account for survey non-respondents and provide comprehensive estimates for the entire universe of plants expected to be directly affected by the final ELG. See *TDD* for further discussion of the sample weights used in this analysis.

[28] Capacity values are from the 2012 EIA-860 database. EPA calculated generation values as a 6-year average (2007-2012) using generation values from the EIA-906/920/923 database. In using the year-by-year generation values to develop an average over the data years, EPA set aside from the average calculation, generation values that are anomalously low. Such low generating output would likely result from a generating unit being out of service for maintenance.

2011, 31 states and Washington, DC have mandatory RPS policies, four of which have Alternative Energy Portfolio Standards. In addition, 8 states have adopted non-mandatory renewable portfolio targets, leaving only 11 states with no standards or goals (PCGCC, 2011). Typically, RPS aim to achieve 1 to 5 percent renewable power generation in the first year and then require increasing percentages every year thereafter, with most states aiming for around 15 to 25 percent renewable power generation by 2020-2025 (PCGCC, 2009). The definition of renewable sources differs among states. Some states allow only new renewables (renewable sources built after a certain year) while some allow all renewables, new and existing. Some RPS also involves credit trading programs, similar to the programs used in the air emissions regulations mentioned in *Section 2.5.2*. Investors and power generators make the decision on what source of renewable energy to acquire or whether to purchase additional credits. Eventually, RPS should result in increased competition, efficiency, and innovation among the renewable energy sectors and should distribute renewable energy at the lowest possible cost (AWEA, 1997). A more recent development in electric portfolio standards is the clean energy standard (CES). A CES in any electric portfolio standard enacts a requirement for the quantity of electric sales that will be met by qualified resources, defined as clean energy sources.[29] Four of the six states that most recently adopted electric portfolio standards chose to enact CES as opposed to RPS (PCGCC, 2011).

2.5.3 Cooling Water Intake Structures Rule

In August 2014, EPA promulgated the final rule for cooling water intake structures (CWIS) at existing electric generating plants and factories under section 316(b) of the Clean Water Act. 33 U.S.C. 1326(b). The rule applies to certain facilities that use cooling water intake structures to withdraw water from waters of the U.S. and have or require an NPDES permit. The rule covers roughly 1,065 existing facilities, including 544 power plants, designed to withdraw at least 2 million gallons per day of cooling water. The rule requires the facilities to choose one of seven options to reduce impingement. Additionally, facilities that withdraw at least 125 million gallons per day must conduct studies to help determine whether and what site-specific controls, if any, would be required to reduce entrainment of aquatic organisms. New units added to an existing facility are required to reduce both impingement and entrainment that achieves one of two alternatives under national entrainment standards. See 79 FR 48300 (August 15, 2014).

EPA estimated that, of the 1,080 plants in the steam electric generating industry, 91 may incur costs under the final CWIS rule.

2.5.4 Coal Combustion Residuals Rule

On April 17, 2015, EPA promulgated national regulations to provide a comprehensive set of requirements for the safe disposal of coal combustion residuals (CCRs) from coal-fired power plants. The CCR rule establishes technical requirements for CCR landfills and surface impoundments under Subtitle D of the Resource Conservation and Recovery Act (RCRA) to address the risks from coal ash disposal – leaking of contaminants into ground water, blowing of contaminants into the air as dust, and the catastrophic failure of coal ash surface impoundments. The rule also sets out recordkeeping and reporting requirements. See 80 FR 21302 (April 17, 2015)

[29] Depending on the way in which clean energy is defined, these sources may include non-renewable electric generation technologies.

2.5.5 Air Emission Regulations

A number of recent air emission regulations affect electric power generators and may change the economics of power production, the profile of the electricity market, and electricity rates. Under these regulations, power generators must meet emission limits by physically reducing air emissions via emission control technology adjusting operations to reduce emissions (*e.g.*, using lower sulfur coal), or by purchasing emissions allowances that permit release of pollutant emissions. These programs have significantly reduced emissions of sulfur dioxide (SO_2) and nitrogen oxides (NOx) from electricity generation. In some instances, these programs have caused, or are expected to cause in the future, changes in electric power sector operations, including increased use of lower pollution fuels, repowering of existing production capacity (*e.g.*, converting simple-cycle natural gas-based steam capacity to a more energy efficient combined cycle operation, which includes a steam and non-steam electricity production capability), accelerated development of new capacity, and earlier retirement of older and typically higher air pollution-intensive capacity for which substantial investments to reduce emissions are not economical to undertake. Air emission control technologies implemented in response to air emissions regulations can also affect the characteristics of wastestreams at steam electric power plants by introducing new wastestreams (*e.g.*, installation of a flue gas desulfurization system) or changing the pollutants loads in plant wastewater.

Acid Rain Program

In 1995, Phase I of the Acid Rain Program was implemented to achieve significant environmental and health benefits by reducing SO_2 and NOx emissions and ambient concentrations. The program affects over 2,000 electric utility plants powered by coal, oil, or natural gas. The program was the first to implement allowance trading in the United States. Instead of a command and control regulatory approach, the allowance trading program is market-based, allocating SO_2 emission credits to each utility and allowing the credits to be bought, sold, or banked (as long as emissions levels are met) for future use. The Acid Rain Program allows flexibility in selecting the most cost-effective approach to reduce emissions. While allowing flexibility in the approach to reducing emissions, the program did not implement an allowance trading system for NOx emissions. During Phase II of the program (starting in 2000), the program set a cap on the number of allowances, ensuring achievement of the intended reductions in pollutant emissions (U.S. EPA, 2009b).

Cross-State Air Pollution Rule

The Cross-State Air Pollution Rule (CSAPR) requires states to significantly improve air quality by reducing power plant emissions that cross state lines and contribute to ozone and fine particle pollution in other states.[30] CSAPR requires a total of 28 states to reduce annual SO_2 emissions, annual NO_X emissions and/or ozone season NO_X emissions to assist in attaining the 1997 ozone and fine particle and 2006 fine particle National Ambient Air Quality Standards (NAAQS). The timing of CSAPR's implementation has been affected by a number of court actions. CSAPR Phase 1 implementation is scheduled for 2015, with Phase II beginning in 2017.

In Phase I, power plants in the affected states will have a combined emissions budget of approximately 3.47 million tons for SO_2, 1.27 million tons for NO_X, 0.63 million tons for ozone-season NO_X. These emissions caps will tighten in 2017 when phase II of the program begins. The combined SO_2 emissions budget will be 2.26 million tons for SO_2, 1.2 million tons for NO_X, and 0.59 million tons for ozone-season NO_X. Phase II will also begin the programs assurance provisions which restrict the maximum amount of

[30] For more information on CSAPR, go to http://www.epa.gov/crossstaterule/.

exceedance of an individual state's emissions budget in a given year through banking or traded allowances to 18% or 21%.

Mercury and Air Toxics Standards

When the Clean Air Act (CAA) was amended in 1990, EPA was directed to control mercury and other hazardous air pollutants from major sources of emissions to the air. For power plants using fossil fuels, the amendments required EPA to conduct a study of hazardous air pollutant emissions (CAA Section 112(n)(1)(A)). The CAA amendments also required EPA to consider the study and other information and to make a finding as to whether regulation was appropriate and necessary. In 2000, the Administrator found that regulation of hazardous air pollutants, including mercury, from coal- and oil-fired power plants was appropriate and necessary (65 FR 79825). On February 16, 2012, EPA promulgated the final Mercury and Air Toxics Standards (MATS) for power plants (77 FR 9304).[31] The rule established uniform national standards to reduce toxic air pollutants from new and existing coal- and oil-fired power plants. Pollutants covered in the standards include metals such as mercury, arsenic, chromium, and nickel; acid gases such as hydrochloric acid and hydrofluoric acid; dioxins and furans; and particulate matter. Steam electric power plants may use any number of practices, technologies, and strategies to meet the new emission limits, including using wet and dry scrubbers, dry sorbent injection systems, activated carbon injection systems, and fabric filters. On June 29, 2015, The Supreme Court reversed the DC Circuit's decision upholding MATS rule. Currently, Agency is reviewing the decision.

Regional Haze

The CAA establishes a national goal for returning visibility to natural conditions through the "prevention of any future, and the remedying of any existing impairment of visibility in Class I areas [156 national parks and wilderness areas], where impairment results from manmade air pollution." On July 1, 1999, EPA established a comprehensive visibility protection program with the issuance of the regional haze rule (64 FR 35714).[32] This rule implements the requirements of section 169B of the CAA amendments and requires states to submit State Implementation Plans (SIPs) establishing goals and long-term strategies for reducing emissions of air pollutants (including SO2 and NO_X) that cause or contribute to visibility impairment. The requirement to submit a regional haze SIP applies to all 50 states, the District of Columbia, and the Virgin Islands. Among the components of a long-term strategy is the requirement for states to establish emission limits for visibility-impairing pollutants emitted by certain source types (including EGUs) that were placed in operation between 1962 and 1977. These emission limits are to reflect Best Available Retrofit Technology (BART). States may perform individual point source BART determinations, or meet the requirements of the rule with an approved BART alternative. An alternative regional SO_2 cap for electricity generating units (EGUs) under Section 309 of the regional haze rule is available to certain western states whose emission sources affect Class 1 areas on the Colorado Plateau. Since 2010, EPA has approved or, in a very few cases, put in place regional haze Federal Implementation Plans for several states.

2.5.6 Greenhouse Gas Emissions Regulations

Though not as prevalent as programs regulating emissions of SO_2 and NOx, carbon dioxide (CO_2) emissions reduction programs are beginning to surface among states and on the national agenda. In the absence of federal action, five states[33] have adopted CO_2 performance standards while another 11 states[34] have enacted

31 For more information on MATS, go to http://www.epa.gov/mats/.

32 For more information, see http://www.epa.gov/visibility/program.html.

33 California, Illinois, Montana, Oregon, and Washington.

utility sector cap and trade programs (PCGCC, 2012). Both the Northeast Regional Greenhouse Gas Initiative (RGGI)[35] and the Western Climate Initiative (WCI)[36] were formed by groups of states in a given region to achieve reductions in CO_2. The RGGI program held its first auction of CO_2 credits on September 25, 2008. According to RGGI, these states have capped and will reduce CO_2 emissions from the power sector by 10 percent by 2018 (RGGI, 2012). The WCI looks to reduce greenhouse gas emissions to levels 15 percent below 2005 emissions by 2020 (WCI, 2012).

In April 2007, the Supreme Court concluded that EPA has the authority to regulate CO_2 and other greenhouse gases under the Clean Air Act.[37] Though this has yet to result in a comprehensive set of rules concerning GHG reductions at the federal level, EPA has begun targeting certain sectors for regulation.

Greenhouse Gas New Source Performance Standard for Electric Generating Units

EPA published the Proposed Greenhouse Gas New Source Performance Standard for Electric Generating Units on April 13, 2012 (U.S. EPA, 2012). This regulation would place requirements on new fossil fuel-fired electric generators greater than 25 megawatt electric to meet an output-based limit of 1,000 pounds of CO_2 per megawatt-hour. After considering public comments received on the proposal, EPA determined that significant revisions to its proposed approach were warranted to tailor emissions limits to types of electricity sector sources.

Clean Power Plan Regulations

On June 2, 2014, EPA proposed *Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Utility Generating Units*, also known as the Clean Power Plan (CPP) rule, under the authority of Section 111(d) of the Clean Air Act. The CPP would establish guidelines for state-based programs for reducing carbon pollution from existing power plants. On October 28, 2014, EPA issued a supplemental proposal to the CPP to address carbon pollution from affected power plants in Indian Country and U.S. territories.

The CPP has two main parts: state-specific goals to lower carbon pollution from power plants and guidelines to help the states develop their plans for meeting the goals. The goals are expressed as emission rates (CO_2 per unit of electricity generated) that states must meet by 2030, while making meaningful progress toward reductions commencing in 2020. States may convert the emission rate-based goal to a mass-based goal, based on EPA guidance issued in November 2014. To set state-specific goals, EPA analyzed the practical and affordable strategies that states and utilities are already using to lower carbon pollution from the power sector, including improving energy efficiency, improving power plant operations, and encouraging reliance on low-carbon energy.

In the June 2014 proposal, EPA did not prescribe a specific set of measures for states to put in their plans. Each state has the flexibility to choose how to meet the goal using a combination of measures that reflect its particular circumstances and policy objectives. EPA did, however, identify a mix of four "building blocks" that inform each state goal and analyzed emissions reductions and costs for various scenarios built around two stringency and implementation schedules and compliance either at the level of individual states or regions.

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[34] Connecticut, Delaware, Florida, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont.

[35] The RGGI consists of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont.

[36] The WCI consists of Arizona, California, Montana, New Mexico, Oregon, Utah, and Washington.

[37] Massachusetts vs. Environmental Protection Agency, 549 U.S. 497

The strategies analyzed by EPA included: (1) reducing the carbon intensity of generation at individual affected EGUs through heat-rate improvements; (2) reducing emissions from the most carbon-intensive affected EGUs with generation from less carbon-intensive affected EGUs (including natural gas combined cycle units that are under construction); (3) reducing emissions from affected EGUs by substituting generation with expanded low- or zero-carbon generation; and (4) reducing emissions from affected EGUs through the use of end-use, demand-side energy efficiency that reduces the amount of generation. EPA estimated the benefits, costs, economic impacts, and changes in the profile of electricity generated as a result of cost-effective measures undertaken to meet the state goals, including the building blocks.

EPA promulgated the CPP rule on August 3, 2015, with mandatory reductions beginning in 2022.[38] The final CPP sets the best system of emission reduction (BSER) for two source-specific CO_2 emissions rates, one for coal steam and oil steam plants and one for natural gas plants. These rates are phased in between 2022 through 2029. As for the proposed rule, state plans will ultimately determine the impacts of the CPP on EGUs, but EPA's analysis of the final CPP rule provides insight on the anticipated effects of the final CPP rule on EGUs. EPA evaluated the impacts of the final rule on EGUs to which the ELGs apply as part of the final ELG analysis and determined that the proposed and final CPP specifications are similar enough that using the proposed rather than final CPP specification does not bias the results of the steam electric ELG analysis. See DCN SE05983 for further discussion.

2.6 Industry Outlook

This section presents a summary of forecasts from the Annual Energy Outlook 2014 (AEO2014) (U.S. DOE, 2014a).

2.6.1 Energy Market Model Forecasts

This section discusses forecasts of electric energy supply, demand, and prices based on data and modeling by the EIA and presented in the AEO2014 (U.S. DOE, 2014a). AEO2014 contains projections of future market conditions through the year 2040, based on a range of assumptions regarding overall economic growth, global fuel prices, and legislation and regulations affecting energy markets. These projections are based on the results from EIA's National Energy Modeling System (NEMS), reflecting all federal, State, and local laws and regulations in effect as of October 2013.

Electricity Demand

EIA projects electricity demand to grow by approximately 0.9 percent annually between 2012 and 2040.[39] Commercial sector demand for electricity is also expected to rise by an estimated 0.8 percent annually. Residential demand is expected to increase by 0.7 percent annually over the same forecast period; this projected increase is in part caused by population growth, temperature assumptions, and continued population shifts to warmer climates with greater cooling requirements. However, energy efficiency improvements offset this increased demand to a degree and average annual electricity demand per household is expected to decline by 4 percent. The industrial sector sees the greatest percentage rise in

[38] For more information see, http://www2.epa.gov/cleanpowerplan/clean-power-plan-final-rule.

[39] With the exception of the market analyses discussed in *Chapter 5*, in analyzing the economic effects of the final ELG, EPA assumed that future electricity demand (and generation) will remain constant throughout the analysis period, and that plants would generate approximately the same quantity of electricity in 2015 as they did on average during 2007-2009. In the market analyses conducted using the Integrated Planning Model (IPM) (see *Chapter 5*), demand growth assumptions are based on AEO2013.

electricity demand between 2012 and 2040 at 30 percent (0.9 percent annually). While electricity demand in the transportation sector is currently small, the EIA projects a strong average annual growth rate of 3.6 percent between 2012 and 2040.

Capacity Retirements

According to AEO2014, fossil fuel-fired capacity will make up the largest share of total retired capacity. Overall, EIA forecasts that 91.1 GW of total fossil-steam capacity will retire between 2012 and 2040, including 30.8 GW of oil and natural gas fired steam capacity. EIA projects that coal will have the largest share of capacity retirements with an expected 50.8 GW of retired capacity by 2040 (52.5 percent of total retirements). An additional 4.8 GW of nuclear plant capacity is also expected to retire during this period.

Capacity Additions

According to AEO2014, 351 GW of new generating capacity will be needed between 2013 and 2040 due to the estimated growth in electricity demand and the need to offset the retirement of 97 GW of existing capacity. These capacity requirements are expected to be met by natural gas, renewable energy, nuclear, and coal power sources – in order of expected contribution. Of the new capacity projected to come on line between 2013 and 2040, approximately 73 percent is projected as natural gas-fired capacity, 24 percent is expected to be fueled by renewables, 3 percent by nuclear energy, and 1 percent by coal-fired plants. The increase in renewable capacity results in part from RPS, as described in *Section 2.5.2*.

Electricity Generation

According to AEO2014, electricity generation from both natural gas- and coal-fired plants will increase to meet growing electricity demand and to offset lost capacity due to plant retirements. Coal-fired plants are expected to remain the largest source of generation until 2035, when natural-gas fired plants become the largest generation source. Natural gas-fired power plants are expected to make up much of the new capacity over the next ten years, while coal-fired generation is projected to decrease between 2012 and 2040, reducing its share of total generation from 37 percent to an estimated 32 percent. The anticipated decrease in the share of coal generation results primarily from competition from natural gas and renewables. Also, concern regarding greenhouse gas emissions and the potential for emissions limits on CO_2 contributes to coal's declining share of total generation. The share of total generation associated with natural gas-fired technologies is projected to increase from 30 percent to 35 percent. The share of total generation from renewable power sources is expected to increase from 12 percent in 2012 to 16 percent of total generation in 2040. Nuclear power generation, however, is expected to decrease from 19 percent to 16 percent as a share of total generation.

Electricity Prices

According to AEO2014, between 2012 and 2040, average annual electricity prices are expected to rise by 13 percent. Electricity prices, which have been declining since 2009, are expected to continue to fall into 2013. Prices then remain relatively constant until 2015 when prices begin an upward trend that generally follows that of the projected price of natural gas. Prices are expected to decline again between 2019 and 2023 but then follow a positive trend for the remainder of the period, with average end-use electricity prices reaching 11.1 cents per kilowatt hour in 2040 (in $2012).

3 Compliance Costs

In developing the final ELGs, EPA assessed the costs and economic impacts of each of the five regulatory options described in *Chapter 1: Introduction*. 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 limitations and standards specified in the final ELGs are based,[40] and to the state and federal government for administering this rule. This chapter describes the methodology and data EPA used to calculate industry-level annualized compliance costs and how these costs were then used to determine whether the final ELGs are economically achievable, whether the compliance costs presents a barrier to entry for new sources, and to characterize economic impacts of the rule.

The *Technical Development Document (TDD)* describes the control technologies and their respective wastewater treatment performance in greater detail (U.S. EPA, 2015c). The *TDD* also describes how EPA estimated plant-specific capital and operation and maintenance (O&M) costs for meeting the limitations and standards specified under each of the five regulatory options.

The following sections of this chapter summarize EPA estimates of the steam electric industry compliance costs based on:

- The costs to existing steam electric power plants for meeting the limitations associated with these regulatory options (*Section 3.1*); and
- The compliance costs to new source steam electric power plants (*Section 3.2*)

EPA determined that state and federal governments would not incur incremental costs for administering the regulatory options and therefore estimated zero cost estimates for this category.[41]

3.1 Costs to Existing Steam Electric Power Plants

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 *TDD* for details.
2. Developing plant-level costs for each wastestream and regulatory option. See *TDD* for details.
3. Estimating the year when each steam electric power plant would be required to meet new effluent limits and 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.

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40 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 limitations and standards in the rule.

41 As discussed in *Section 10.7: Paperwork Reduction Act of 1995*, EPA expects that the final ELGs will not impose additional administrative cost to the State and federal governments.

As described below, EPA generally discounted costs to 2015, the rule promulgation year, and reports costs in 2013 dollars.

3.1.1 Analysis Approach and Data Inputs

Plants-Specific Costs Approach

The final ELGs are expected to potentially impose incremental compliance costs on steam electric power plants that generate the wastestreams addressed by the final ELGs.

As detailed in the *TDD*, EPA developed costs for steam electric power plants to implement treatment technologies or process changes to control the wastestreams addressed by the final rule (*e.g.*, bottom ash, fly ash, flue gas desulfurization (FGD), leachate, FGMC, and gasification wastewater). Under the five regulatory options, a plant may need to meet limitations or standards for one or more wastestreams, depending on the plant configuration, technologies in use, or other site-specific factors (see *TDD* for details on technology basis assumed for each option).

EPA assessed the operations and treatment system components in place at a given plant in the baseline, identified equipment and process changes that the plant would likely make to achieve the final ELGs, and estimated the cost to implement those changes. The cost estimates reflect the incremental costs attributed only to the final ELGs. For example, plants that do not generate a wastewater or that already meet the limitations or standards do not incur costs.

In identifying the plants that would incur costs under each of the regulatory options, EPA also accounted for plant retirements and fuel conversions, as well as changes in plants' ash-handling and wastewater treatment practices, expected to occur before the plants would need to meet the final effluent limitations and standards in this rule. EPA made adjustments to the industry profile based on company announcements, as of August 2014, for changes in plant operations made as of August 2014.

EPA performed two sets of parallel analyses to demonstrate how the CPP rule may affect the costs of this final rule. This document primarily presents information for analyses that include the anticipated effects of the CPP rule.[42] See *Appendix B* for results of the analyses EPA conducted using costs developed without those effects.

Additionally, EPA performed two sets of parallel analyses to demonstrate how expected operational changes to comply with the final CCR rule affect plant specific costs. As noted in *Section 1.2*, this document primarily presents information associated with plant-specific costs that account for the CCR rule. See *Appendix C* for results of the analyses EPA conducted using costs developed without accounting for the CCR rule.

The *TDD* details the methodology EPA used to develop plant-level cost estimates for each wastestream and regulatory option, adjust the industry profile to reflect retirements and conversions, and account for the effect of the CCR and CPP rules.

[42] At the time it conducted these analyses, the CPP had not yet been finalized, and thus EPA used the proposed CPP for its analyses. Now that the CPP has been promulgated, and it is clear that the final CPP does not differ substantially from the proposed CPP, EPA concludes that its cost and loadings estimates using the proposed CPP are a reasonable and sound approximation of the cost and loadings estimates associated with this rule in light of the final CPP.

Plant-Level Costs

EPA estimated compliance costs for the 681[43] steam electric power plants that completed the industry survey (surveyed plants) and used sample weights to estimate total compliance costs for the remaining 399 plants, for a total universe of 1,080 steam electric power plants. EPA estimates that only a subset of the 1,080 steam electric power plants – up to 145 plants for the most stringent regulatory option (Option E) analyzed by EPA – may incur non-zero compliance costs, depending on their wastestreams and existing control technologies. The number of plants reflects the anticipated effects of the CPP rule which reduces the number of plants incurring non-zero compliance costs under the most stringent option (Option E) from 195 plants to 145 plants after accounting for projected conversions and retirements.[44] Since all 145 plants incurring costs are coal- or petroleum coke-fired and have a sample weight of 1, the sum of costs for the 145 plants also represents the total costs for the entire universe of 1,080 plants.

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. EPA assumes that plants incur all capital costs three years after their permit is renewed to incorporate the new limitations or standards (see *Development of Technology Implementation Years* below). For this analysis, all compliance technologies are assumed to have a useful life of 20 years.
- *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. Steam electric power plants are expected to incur these costs only once during their technology implementation year.
- *Annual fixed O&M costs*, if applicable, include regular *annual* monitoring and oil storage costs. 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, oil conveyance operation and maintenance, 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 expected 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 expected 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 expected to incur every five years, beginning five years after the technology implementation year.

[43] See TDD for details on the industry survey.

[44] This estimate reflects coal-fired generating units expected to be converted or retired as a result of the CPP rule through 2025 (based on the analysis year corresponding to 2023 in EPA's analysis of the proposed CPP rule). Without the CPP rule effects, up to 195 plants may incur non-zero compliance costs under Option E. See *Appendix B*.

- *6-Yr fixed O&M costs*, if applicable, include mercury analyzer operating and maintenance costs that plants are expected to incur every six years, beginning in the technology implementation year.
- *10-Yr fixed O&M costs*, if applicable, include capital costs for water trucks, and savings from not needing to periodically maintain ash/FGD pond systems. Steam electric power plants are assumed to purchase water trucks every 10 years, beginning in the technology implementation year. Plants are expected 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 facilities, EPA estimated that facilities would be able to coordinate the plants' implementation of wastewater treatment systems during already scheduled downtime. As described in the next section, EPA accounted for time necessary for plants to plan and coordinate technology implementation to fit within their routinely scheduled outages.

Development of 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 and society would incur due to the final ELGs. This profile is used to estimate the annualized costs to the steam electric industry and society.

As discussed in the final rule preamble, EPA envisions that each plant to which the final ELGs 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 in the rule, EPA considered the magnitude and complexity of process changes and new equipment installations that would be required at facilities to meet the requirements of the rule. As described in greater detail in the preamble to the final rule, where the BAT limitations in this rule are more stringent than previously established BPT limitations, those limitations do not begin to apply until a date determined by the permitting authority that is as soon as possible beginning November 1, 2018 (approximately three years following promulgation of the final rule), and they must be achieved by December 31, 2023 (approximately eight years from the promulgation of this rule). The final rule takes this approach in order to provide the time that many facilities need to raise capital, plan and design systems, procure equipment, and construct and then test systems. Moreover, this enables facilities to take advantage of planned shutdown or maintenance periods to install new pollution control technologies. EPA's decision is designed to allow 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 know, for each plant, exactly what date the permitting authority will determine is "as soon as possible" within the period beginning November 1, 2018, and ending December 31, 2023, for purposes of determining exactly when plants will have to meet the new effluent limitations and standards. However, EPA would generally expect that plants would meet the new effluent limitations and standards in a somewhat staggered fashion throughout this period, which would reflect the fact that (1) some plants may be able to meet the limitations and standards sooner than others, (2) all permits are not re-issued at the same time due to their 5-year permit term, and (3) the implementation window is in part intended to ensure no adverse effects on electricity availability. Thus, for the cost and economic impact analyses, EPA assumed that, following promulgation of the final rule, plants would implement control technologies during the third year after issuance of their National Pollutant Discharge Elimination System (NPDES) permit.[45] EPA also assumed that

[45] These assumed compliance years do not necessarily correspond to the actual years in which individual facilities would be required to implement control technologies. Instead, these assumptions reflect the approximate years in

NPDES permits would be issued in a timely manner (every five years, when each permit expires, with no "backlog"). Although EPA recognizes that this may not be true for all permits, this assumption tends to result in a more conservative cost estimate. Using these assumptions, EPA estimated that steam electric power plants will implement the relevant control technologies within the 5-year window of calendar year 2019 (as a proxy for November 2018) through calendar year 2023. This is a reasonable approximation of the period when steam electric power plants will be making changes to their operations to meet the limitations and standards, following the rule effective date of November 1, 2018.

As described in Section XVI of the preamble, the requirements for new source direct and indirect discharges (NSPS and PSNS) provide no extended implementation period. NSPS apply when any NPDES permit is issued to a new source direct discharger, following the effective date of this rule (November 2018); PSNS apply to any new source discharging to a POTW, as of the effective date of the final rule. For the purpose of this analysis, EPA assumed the same implementation years as described above for direct dischargers, based on the plants' existing NPDES permits.

The assumed technology implementation years may understate the costs incurred by indirect dischargers (to which the requirements will apply as of November 2018) or by plants whose permit will be issued between November and December 2018. However, EPA estimated the impact of assuming a different timing for compliance costs at these plants to be small, *i.e.*, in the range of 0.5 to 0.7 percent of the total industry costs discussed later in this section.

Table 3-1 provides counts of steam electric power plants that incur costs under the most stringent regulatory option (Option E) and their total generation capacity by estimated technology implementation year based on the expected year of permit issuance. As shown in the table, EPA anticipates a somewhat uniform distribution of costs over the 5-year implementation period used in the analysis, with the largest number of plants (both by count and generating capacity) incurring costs in 2019.

Table 3-1: Counts of Steam Electric Power Plants Potentially Incurring Costs and Their Total Generating Capacity by Estimated Technology Implementation Year

Technology Implementation Year	Plant Counts[a]		Total Capacity	
	Counts	% of Total	Capacity (MW)	% of Total
2019	34	23.4%	41,507	23.5%
2020	22	15.2%	23,542	13.3%
2021	24	16.6%	35,264	20.0%
2022	34	23.4%	38,491	21.8%
2023	31	21.4%	37,952	21.5%
Total	**145**	**100.0%**	**176,756**	**100.0%**

a. Out of 1,080 steam electric power plants in the total universe.
Source: U.S. EPA Analysis, 2015.

As noted previously, EPA accounted for retirements and conversions that are expected to occur before plants will have to meet the new final limitations and standards. In particular, EPA did not assign costs to plants that have announced retirements or conversions through the end of 2023. This approach is reasonable given that EPA identified only one plant closing before 2023 for which the assumed technology implementation year would precede the announced retirement or conversion year (by one year).

which technology implementation would reasonably be expected to occur across the universe of steam electric plants, and thus provide a practical basis for the cost and economic impact analysis.

<u>*Development of Total Compliance Costs*</u>

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:

- EPA estimated compliance costs (including zero costs) for each of the 681 steam electric power plants surveyed (see *TDD* for details).
- 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 2013 dollars, using the Construction Cost Index (CCI) from McGraw Hill Construction (2014), the Employment Cost Index (ECI) published by the Bureau of Labor Statistics (BLS) (2013), and the Gross Domestic Product (GDP) deflator index published by the U.S. Bureau of Economic Analysis (BEA) (2014).[46]
- EPA discounted all cost values to 2015, using a rate of 7 percent.[47]
- 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: [47]
  - Capital costs of each compliance technology: 20 years
  - Initial one-time costs: 20 years[48]
  - 3-Yr O&M: 3 years
  - 5-Yr O&M: 5 years
  - 6-Yr O&M: 6 years
  - 10-Yr O&M: 10 years
- 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.
- EPA applied sample weights to these cost values to estimate costs for the total of 1,080 steam electric power plants (for details on weights development see *TDD*). Since all plants incurring non-zero costs have a sample weight of 1, the sum of costs for the surveyed plants also represents the total costs for the entire universe of 1,080 plants.

For the assessment of compliance costs to steam electric power plants, 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. EPA calculated the after-tax value of compliance costs by applying combined federal and State tax rates to the

[46] Specifically, EPA brought all compliance costs to an estimated technology implementation year using the Construction Cost Index (CCI) from McGraw Hill Construction (2014) or the Employment Cost Index (ECI) from the Bureau of Labor Statistics (2013), 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 2013 dollars, the Agency deflated the nominal dollar values to 2013 using the average of the year-to-year changes in the Gross Domestic Product (GDP) deflator index published by the U.S. Bureau of Economic Analysis (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 2013.

[47] The rate of 7 percent is used in the cost impact analysis as an estimate of the opportunity cost of capital.

[48] EPA annualized these non-equipment outlays over 20 years to match the maximum expected performance life of compliance technology components.

pre-tax cost values for privately owned for-profit plants.[49] For this adjustment, EPA used State corporate rates from the Federation of Tax Administrators (2012) combined with federal corporate tax rate schedules from the Department of the Treasury, Internal Revenue Service (2008). As discussed in the relevant sections of this document, 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, EPA uses pre-tax costs.

3.1.2 Key Findings for Regulatory Options

Table 3-2 presents compliance cost estimates for each of the five regulatory options. The table lists the options in order of increasing total annualized compliance costs.

EPA estimates that, on a *pre-tax* basis, steam electric power plants would incur annualized costs of meeting the final ELGs ranging from $121.9 million under Option A to $553.9 million under Option E. On an *after-tax* basis, the costs range from $89.4 million to $377.1 million. [50] EPA estimates the total annualized after-tax compliance costs of the option selected for the final limitations for existing plants (Option D) to be $339.6 million.

Table 3-2: Total Annualized Compliance Costs (in millions, $2013, at 2015)

ELG 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
Option A	$66.4	$0.0	$55.5	$121.9	$48.4	$0.0	$41.0	$89.4
Option B	$119.3	$0.0	$84.9	$204.2	$86.1	$0.0	$61.9	$148.0
Option C	$250.2	$0.0	$149.8	$400.1	$169.1	$0.0	$102.9	$272.0
Option D	$300.4	$0.0	$195.7	$496.2	$204.4	$0.0	$135.1	$339.6
Option E	$334.2	$0.0	$219.6	$553.9	$226.6	$0.0	$150.5	$377.1

a. Initial one-time cost (other than capital technology costs), if applicable, consist of a one-time cost to close bottom ash system.
Source: U.S. EPA Analysis, 2015.

Table 3-3 reports costs at the level of a North American Electric Reliability Corporation (NERC) region.[51] As explained in *Chapter 2: Profile of the Electric Power Industry*, NERC is responsible for the overall reliability, planning, and coordination of the power grids; NERC consists of regional organizations that are each responsible for the coordination of bulk power policies that affect their regions' reliability and quality of service. Each NERC region is responsible for managing electricity reliability issues in its region, based on available capacity and transmission constraints. Service areas of the member plants determine the boundaries

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

50 The compliance costs used in this analysis reflect anticipated unit retirements, conversions, and repowerings announced through August 2014 and scheduled to occur by 2023.

51 The NERC regions used for the analysis of compliance costs to steam electric power plants include: ASCC – Alaska Systems Coordinating Council; FRCC – Florida Reliability Coordinating Council; HICC – Hawaii Coordinating Council; MRO – Midwest Reliability Organization; NPCC – Northeast Power Coordinating Council; RFC – ReliabilityFirst Corporation; SERC – Southeastern Electric Reliability Council; SPP – Southwest Power Pool; TRE – Texas Reliability Entity; and WECC – Western Energy Coordinating Council. No steam electric power plant is expected to incur compliance costs in the ASCC and HICC NERC regions.

of the NERC regions. Because of differences in operating characteristics of steam electric power plants across NERC regions (*e.g.*, fuel mix), as well as differences in the baseline economic and electric power system regulatory circumstances of the NERC regions themselves, the final ELGs 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, whereas two NERC regions, ASCC and HICC, have no costs for any of the five options that EPA evaluated as part of final rule development.

Table 3-3: Annualized Compliance Costs by NERC Region (in millions, $2013, at 2015)

NERC Region[a]	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
Option A								
ASCC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
FRCC	$0.0	$0.0	$0.1	$0.1	$0.0	$0.0	$0.1	$0.1
HICC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
MRO	$1.6	$0.0	$0.9	$2.5	$1.4	$0.0	$0.9	$2.3
NPCC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
RFC	$22.0	$0.0	$12.9	$34.9	$13.9	$0.0	$8.0	$21.9
SERC	$40.4	$0.0	$41.1	$81.4	$31.4	$0.0	$31.5	$62.9
SPP	$1.1	$0.0	$0.4	$1.5	$0.7	$0.0	$0.2	$0.9
TRE	$0.7	$0.0	$0.4	$1.1	$0.7	$0.0	$0.4	$1.1
WECC	$0.5	$0.0	($0.2)	$0.3	$0.4	$0.0	($0.1)	$0.2
Total	**$66.4**	**$0.0**	**$55.5**	**$121.9**	**$48.4**	**$0.0**	**$41.0**	**$89.4**
Option B								
ASCC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
FRCC	$0.8	$0.0	$0.5	$1.3	$0.8	$0.0	$0.5	$1.3
HICC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
MRO	$2.4	$0.0	$1.5	$3.9	$2.3	$0.0	$1.4	$3.7
NPCC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
RFC	$47.3	$0.0	$26.6	$73.9	$29.8	$0.0	$16.6	$46.4
SERC	$64.7	$0.0	$54.6	$119.3	$50.2	$0.0	$42.1	$92.3
SPP	$2.6	$0.0	$1.2	$3.8	$1.6	$0.0	$0.8	$2.4
TRE	$1.0	$0.0	$0.7	$1.7	$1.0	$0.0	$0.7	$1.7
WECC	$0.5	$0.0	($0.2)	$0.3	$0.4	$0.0	($0.1)	$0.2
Total	**$119.3**	**$0.0**	**$84.9**	**$204.2**	**$86.1**	**$0.0**	**$61.9**	**$148.0**
Option C								
ASCC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
FRCC	$0.8	$0.0	$0.5	$1.3	$0.8	$0.0	$0.5	$1.3
HICC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
MRO	$8.5	$0.0	$3.2	$11.7	$6.2	$0.0	$2.2	$8.4
NPCC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
RFC	$126.8	$0.0	$65.5	$192.4	$78.6	$0.0	$40.7	$119.3
SERC	$101.8	$0.0	$74.9	$176.7	$75.5	$0.0	$55.7	$131.2
SPP	$10.7	$0.0	$5.2	$15.9	$6.6	$0.0	$3.2	$9.8
TRE	$1.0	$0.0	$0.7	$1.7	$1.0	$0.0	$0.7	$1.7
WECC	$0.5	$0.0	($0.2)	$0.3	$0.4	$0.0	($0.1)	$0.2
Total	**$250.2**	**$0.0**	**$149.8**	**$400.1**	**$169.1**	**$0.0**	**$102.9**	**$272.0**

Table 3-3: Annualized Compliance Costs by NERC Region (in millions, $2013, at 2015)

NERC Region[a]	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
Option D								
ASCC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
FRCC	$0.8	$0.0	$0.5	$1.3	$0.8	$0.0	$0.5	$1.3
HICC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
MRO	$17.1	$0.0	$11.6	$28.7	$13.8	$0.0	$9.7	$23.5
NPCC	$0.4	$0.0	$0.6	$1.0	$0.2	$0.0	$0.4	$0.6
RFC	$147.0	$0.0	$83.6	$230.6	$90.9	$0.0	$51.7	$142.5
SERC	$112.3	$0.0	$84.2	$196.5	$83.5	$0.0	$62.8	$146.3
SPP	$15.1	$0.0	$11.2	$26.3	$9.5	$0.0	$7.0	$16.5
TRE	$1.0	$0.0	$0.7	$1.7	$1.0	$0.0	$0.7	$1.7
WECC	$6.6	$0.0	$3.3	$10.0	$4.7	$0.0	$2.4	$7.1
Total	**$300.4**	**$0.0**	**$195.7**	**$496.2**	**$204.4**	**$0.0**	**$135.1**	**$339.6**
Option E								
ASCC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
FRCC	$0.8	$0.0	$0.5	$1.3	$0.8	$0.0	$0.5	$1.3
HICC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
MRO	$19.6	$0.0	$12.9	$32.6	$15.8	$0.0	$10.7	$26.5
NPCC	$0.8	$0.0	$0.7	$1.5	$0.5	$0.0	$0.4	$0.9
RFC	$166.0	$0.0	$98.3	$264.3	$102.6	$0.0	$60.8	$163.4
SERC	$119.8	$0.0	$89.0	$208.9	$88.6	$0.0	$66.1	$154.7
SPP	$18.4	$0.0	$13.1	$31.5	$11.8	$0.0	$8.4	$20.1
TRE	$2.2	$0.0	$1.7	$3.9	$1.8	$0.0	$1.3	$3.1
WECC	$6.6	$0.0	$3.3	$10.0	$4.7	$0.0	$2.4	$7.1
Total	**$334.2**	**$0.0**	**$219.6**	**$553.9**	**$226.6**	**$0.0**	**$150.5**	**$377.1**

a. Initial one-time cost (other than capital technology costs), if applicable, consist of a one-time cost to close bottom ash system.
Source: U.S. EPA Analysis, 2015.

3.1.3 Key Uncertainties and Limitations

Economic analyses are not perfect predictions and thus, like all such analyses, this analysis has some uncertainties and limitations. Notably, annualized compliance costs depend on the assumed technology implementation year. For the purpose of the cost and economic impact analyses, EPA determined years in which technology implementation would reasonably be expected to occur across the universe of steam electric power plants, based on plant-specific information about existing NPDES permits and extrapolating permit issuance dates by five years assuming permit writers have no “backlog.” 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 final ELGs.

3.2 Costs to New Sources

Electric power generating units that meet the definition of a “new source” would be required to achieve the final New Sources Performance Standards (NSPS), in the case of direct dischargers, or Pretreatment Standards for New Sources (PSNS), in the case of indirect dischargers. This section summarizes the data and methodology used to estimate compliance costs for new generating units at steam electric power plants (for a more detailed description of the methodology, see *TDD*). The section also assesses the relative magnitude of the compliance costs by comparing them to the costs of new coal steam generation.

EPA's final NSPS and PSNS rule is based on the suite of technologies identified for Option F. This section discusses the development and the impact of compliance costs on new units under Option F only.

3.2.1 Analysis Approach and Data Inputs

EPA developed compliance costs for new coal-fired units using a methodology similar to the one used to develop compliance costs for existing plants (see *TDD* for details). EPA did not have information about which plants will construct new units, the exact characteristics of such units, or the timing of new unit construction; in fact, neither the EIA projections discussed in *Chapter 2* nor the IPM base case discussed in *Chapter 5* show any new coal-fired power plant being built to meet electricity demand over the next few decades.[52] Instead, EPA calculated and analyzed compliance costs for a variety of hypothetical plant and unit configurations. The Agency treated the incurrence of costs in this analysis as though new units would be constructed, and additional wastewater treatment costs incurred, as of the rule promulgation, *i.e.*, 2015. This is a conservative assumption since new sources would not incur costs until there is an NPDES permit applying the NSPS to them.

EPA's estimates for compliance costs for new units are based on the net difference in costs between wastewater treatment system technologies that would likely have been implemented for new units under the previously established regulatory requirements, and those that would likely be implemented because of the final rule.

Compliance costs for new units under the final NSPE and NSPS (Option E) include capital costs, annual fixed and variable O&M costs, 6-year fixed O&M costs, and 10-year O&M savings from not needing to periodically maintain ash/FGD pond systems. EPA made the same adjustments to the plant-specific costs for new plants described in the *TDD*, as those made to develop total compliance costs for existing plants:

- First, EPA brought all compliance costs to 2015 using CCI (or ECI), and restated in 2013 dollars using GDP Deflator.
- EPA then annualized each non-annual cost component over the expected useful life of the technology/processes it represents (capital cost over 20 years, 6-year O&M cost over 6 years, and 10-year O&M savings over 10 years) using 7 percent as the assumed cost of capital.
- Finally, EPA added these annualized capital and O&M costs to annual O&M costs.

Table 3-4 presents estimated new unit compliance costs under the selected regulatory option for new sources (Option F). As described in the *TDD*, EPA estimated costs for coal steam units of different sizes (350 MW, 600 MW, and 1,300 MW) and two principal plant configurations: a new unit at a new plant; and a new unit at an existing plant. As shown in the table, costs vary depending on unit capacity and plant configuration. For a given generation capacity, compliance costs are higher for new units at existing plants than for new units at new plants. Thus, EPA estimates that a new 1,300 MW unit would incur a total annualized compliance cost of about $1,354/MW when located at a new plant, and a cost of $16,511/MW when added to an existing plant. For more details on the methodology used to estimate compliance costs for new units, see the *TDD.*

[52] The AEO2014 Reference case projects 351 GW of new capacity from 2013 to 2040 (U.S. DOE, 2014a). Approximately 73 percent of the capacity additions are natural gas-fired plants, with the remainder composed almost exclusively of renewables (24 percent) and nuclear (3 percent). Only 1 percent of the additional capacity is expected to come from coal-fired generation, with these additions occurring in the early years of the AEO projection period (2013-2020).

Table 3-4: Annualized Pre-tax Compliance Costs for a New Unit Under Option F (Millions; at 2015; $2013)

New Unit and Plant Configuration	Capital Costs	Annual O&M	Total Annualized Compliance Costs	Unit Costs ($/MW)		
				Capital Costs	O&M Costs	Annualized Compliance Costs
New Unit at New Plant						
350 MW	$10,730,428	$539,007	$1,485,621	$30,658	$1,540	$4,245
600 MW	$11,118,325	$611,947	$1,592,780	$18,531	$1,020	$2,655
1300 MW	$10,826,078	$805,469	$1,760,521	$8,328	$620	$1,354
New Unit at Existing Plant						
350 MW	$71,056,700	$5,007,702	$11,276,159	$203,019	$14,308	$32,218
600 MW	$81,052,261	$6,653,602	$13,803,845	$135,087	$11,089	$23,006
1300 MW	$113,210,748	$11,476,632	$21,463,823	$87,085	$8,828	$16,511

Source: U.S. EPA Analysis, 2015

3.2.2 Key Findings for Regulatory Options

EPA assessed the effects of final ELG requirements for new units by comparing the incremental costs for new units to the overall cost of *building and operating* new units, on a per MW basis. This analysis assesses the requirements and costs imposed on new generating units in relation to the costs that would be incurred for building and operating new units *without the new unit requirements*.[53]

To assess the relative magnitude of compliance costs for new units, EPA compared the pre-tax costs presented in Section *3.2.1*, to the total cost of building and operating a new coal-fired plant, also on a pre-tax and per MW basis. EPA obtained the overnight capital and O&M costs of building and operating a new coal-fired plant used in the Energy Information Administration's Annual Energy Outlook 2014 (AEO2014) to estimate the costs of meeting additional electricity demand for different generation technologies; these costs are based on a new dual-unit plant with a total generation capacity of 1,300 MW (U.S. DOE, 2014a).[54] Accordingly, EPA used the ELG cost estimates for the 1,300-MW plant presented in *Table 3-4* to coincide with the new scrubbed coal plant size assumed in DOE's AEO2014.[55]

EPA also estimated annual fuel costs for operating the unit based on an assumed capacity factor of 90 percent, and the heat rate and projected price of coal delivered to the power sector in AEO2014. EPA annualized new dual-unit plant building and operating costs over 20 years using a rate of 7 percent.[56] EPA then compared the

[53] Note that the market analyses described in Chapter 5 also incorporate costs to new sources as part of inputs to the Integrated Planning Model (IPM). This analysis tests the impact of the new unit requirements in electricity markets accounting for the expected number and timing of new unit installations, and provides additional insight on whether the costs of meeting the standards specified by the final NSPS and PSNS would affect future capacity additions. Since IPM projects no new coal-fired generating plant in the Base Case, however, the market analysis does not offer additional insight on the impacts of the NSPS/ PSNS compliance costs on new generating capacity.

[54] As defined by the Energy Information Administration, "Overnight cost" is an estimate of the cost at which a plant could be constructed assuming that the entire process from planning through completion could be accomplished in a single day. This concept avoids issues and assumptions concerning the change in costs, and their accumulation over time, during the period of plant construction.

[55] AOE 2014 does not provide costs for new scrubbed coal plants of different sizes.

[56] EPA's assumption that a new coal unit will operate for 20 years is based on EIA NEMS Electricity Market Module assumption. This period is considerably shorter than the actual performance life of generating units constructed and operated over the past several decades. In addition, the assumption of a 20-year operating life

estimated compliance costs for new units to the costs of constructing and operating new coal steam capacity. *Table 3-5* presents the results of this comparison. Compliance costs for a new unit represent 0.3 percent of the total annualized cost of a new plant, while compliance costs for adding a new unit at an existing plant represent 3.3 percent of the annualized cost of building and operating a new plant.

Table 3-5: Capital and O&M Costs for New 1,300 MW Coal-Fired Steam Electric Power Plant per MW of Capacity (Millions; at 2015; $2013)

Cost Component	Costs of New Coal-fired Generation ($2013/MW)[a]	Incremental Compliance Costs ($2013/MW)[b]		% of New Generation Cost	
		New Plant	Existing Plant	New Plant	Existing Plant
Capital	$3,058,861	$8,328	$87,085	0.3%	2.8%
Annual Non-Fuel O&M	$69,630	$620	$8,828	0.3%	3.9%
Annual Fuel O&M	$157,737				
Total annualized costs	**$497,213**	**$1,354**	**$16,511**	**0.3%**	**3.3%**

a. Source: New unit total cost value from Table 8.2 EIA NEMS Electricity Market Module. AEO2014 Documentation. Available at http://www.eia.gov/forecasts/aeo/assumptions/pdf/electricity.pdf. Capital costs are based on the total overnight costs for new scrubbed coal dual-unit plant, 1,300-MW capacity coming online in 2017. EPA restated costs in 2013 dollars using the construction cost index. Total annual O&M costs assume 90% capacity utilization.

b. Incremental costs for new 1,300 MW unit for Option F. Incremental costs for new 1300 MW unit for Option E. Range represents the costs for a new unit at a newly constructed plant (lower bound) and new unit at existing plant (upper bound).

c. Fuel costs estimated assuming heat rate of 8,800 Btu/kWh (AEO2014) and coal price delivered to the power sector of 2.27 $/Mbtu (AEO2015, projected costs in 2017 in 2013$).

Sources: U.S. DOE, 2014a; U. S. EPA Analysis, 2015.

3.2.3 Key Uncertainties and Limitations in EPA's Estimates

Despite EPA's use of the best available information and data available, including information provided to EPA in the industry survey, this analysis has uncertainties and limitations.

First, EPA notes that no coal steam plants have been announced, nor are projected in AEO2014, making the assessment of the relative costs and of any barrier the final ELGs may pose to additional generation hypothetical. Similarly, results of the electricity market model using the Integrated Planning Model (*Chapter 5*) shows no additional coal steam capacity being built through 2050 in the Base Case (in the absence of the ELGs) or in the policy cases (with the ELGs), and do not offer a basis for determining, using IPM, whether the ELGs present a cost barrier to new coal generation. However, as discussed in *Chapter 5*, the IPM results demonstrate that the ELGs do not pose a barrier to new electricity generation overall; the model shows essentially negligible differences in new capacity projected in IPM under the final rule option.

Second, EPA made assumptions about plant characteristics in the absence of the final rule. These assumptions affect the types of wastestreams that a plant would generate and changes needed to meet the final limitations and standards. To the extent that the characteristics of new plants differ from EPA's assumed characteristics, the costs may be under or overstated.

Finally, the costs of implementing and operating compliance technology vary based on the size of the generating unit which this technology is assumed to support and plant configuration. To the extent that the size and configuration of a potential new coal unit is different from assumptions that underlay new capacity costs, the relative magnitude of the compliance costs for new steam electric capacity may be under- or over-

also aligns the annualization bases for (1) new unit compliance costs and (2) the cost of constructing and operating a new generating unit, independent of ELG requirements.

estimated. EPA used data from EIA on the cost of additional capacity based on a 1,300 MW plant, which is the size plant EIA expects would be constructed when adding new scrubbed coal capacity (AEO2014). The cost of building new capacity for a smaller plant is expected to be higher on a per MW basis than those of a 1,300 MW plant.

4 Cost and Economic Impact Screening Analyses

4.1 Analysis Overview

EPA assessed the costs and economic impacts of the five regulatory options defined in *Chapter 1: Introduction* and discussed elsewhere in this document in two ways:

1. A screening-level assessment reflecting baseline operating characteristics of steam electric power plants and with assignment of estimated compliance costs to those plants. This analysis assumes no changes in baseline operating characteristics – *e.g.*, quantity of generated electricity and revenue – as a result of the final ELG requirements. 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 the Integrated Planning Model (IPM) (the Market Model Analysis). This analysis, which provides a more comprehensive indication of the economic achievability of the final ELGs and final rule options that EPA evaluated, including an assessment of plant closures, is discussed in *Chapter 5: Assessment of the Impact of the Final ELG Options in the Context of National Electricity Markets*. Unlike the preceding analysis discussed in this chapter, the Market Model Analysis accounts for expected changes in the operating characteristics of plants from both:
   - Estimated changes in electricity markets and operating characteristics of plants *independent of the regulatory options*, and
   - Estimated changes in markets and operating characteristics of plants *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 expected of the regulatory options. As discussed in *Chapter 2: Profile of the Electric Power Industry*, the majority of steam electric power plants (62 percent) operate in states with regulated electricity markets. EPA estimates that plants located in these states may be able to recover 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.[57]

In assessing the cost impact of the five 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 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. 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, EPA judges that assuming zero cost pass-through is appropriate as a screening-level, upper bound estimate of the potential cost impact from the final ELGs to steam electric power plants and their parent entities. To the extent that some steam electric power plants are able to recover some of the increased production costs in increased prices, this analysis overstates plant-level impacts. 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.

4.2.1 Analysis Approach and Data Inputs

As described in *Chapter 3: Compliance Costs*, EPA expects all steam electric power plants to meet the effluent limitations and standards beginning November 1, 2018, with economic impact analyses generally conducted assuming a 5-year window of 2019 through 2023 during which plants would implement any needed changes in operations, including installation of compliance technologies.

In comparing compliance costs to revenue at the plant level, EPA used a single year of 2015 as the basis for the analysis. Specifically, EPA compared annualized after-tax compliance costs[58] (see *Chapter 3*) with estimated plant revenue as of 2015.[59] To estimate 2015 plant revenue for use in this analysis, EPA assumed that future electricity demand (and generation) will remain constant throughout the analysis period, and that plants would generate approximately the same quantity of electricity in 2015 as they did on average during 2007 through 2012.

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, EPA multiplied the 6-year average of electricity generation values over the period 2007 to 2012 from the EIA-906/920/923 database by 6-year

[57] As discussed in *Chapter 2: Profile of the Electric Power Industry*, while 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.

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

[59] Although steam electric plants are expected to implement control technologies in future years, because this analysis relies on a ratio of cost to revenue as opposed to absolute values, a cost to revenue ratio for a given plant will be the same in years beyond 2015 as long as cost and revenue values are as of the same year and the basis for projecting cost and revenue values is the same. That is, beyond 2015, cost and revenue values are assumed to change at the same rate and thus the ratio of these values will be constant over time.

average electricity prices over the period 2007 to 2012 from the EIA-861 database (U.S. DOE, 2012c; U.S. DOE, 2012d).[60]

To provide cost and revenue comparisons on a consistent analysis-year (2015) and dollar-year (2013) basis, EPA made the following adjustments:

- The EIA electricity price data are reported in nominal dollars of each year. EPA's first step in calculating plant revenue was to restate these values in 2013 dollars using the Gross Domestic Product (GDP) deflator index published by the U.S. Bureau of Economic Analysis (BEA) (2014). These individual yearly values were then averaged and brought forward to 2015 using electricity price projections from the Annual Energy Outlook publication for 2013 (AEO2013) (U.S. DOE, 2013a).[61,62,63]
- Compliance cost values were originally estimated as of 2010. To bring all compliance costs, except the initial planning costs, to 2015, EPA used the average of the year-to-year changes in the McGraw Hill Construction's (2014) Construction Cost Index (CCI) over the most recent ten-year reporting period. Because the CCI is a nominal cost adjustment index, the resulting technology cost values are as of the assumed year of compliance, 2015, and in 2015 dollars. To re-state compliance cost values in 2013 dollars, the Agency used the average of the year-to-year changes in the GDP Deflator index over the most recent ten-year reporting period.
- To bring the one-time cost for closing a bottom ash system to 2015, EPA used the average of the year-to-year changes in the Employment Cost Index (ECI) from the Bureau of Labor Statistics (BLS) (2013) over the most recent ten-year reporting period. EPA used a different index for this cost component because it consists mostly of labor (as compared to other compliance costs described above, which consist of a mix of equipment, material, and labor). The resulting cost values are as of 2015 and in 2015 dollars. To re-state these cost values in 2013 dollars, the Agency used the average of the year-to-year changes in the GDP Deflator index over the most recent ten-year reporting period.

In the cost-to-revenue comparisons, EPA used cost-to-revenue ratios of 1 and 3 percent as markers of potential impact. EPA compared plant-level costs and revenue *on a non-weighted basis* and determined the number of instances when plants incurred costs in ranges of "less than 1 percent of revenue," "between 1 and 3 percent of revenue," and "greater than 3 percent of revenue." Plants incurring costs below 1 percent of revenue are unlikely to face material economic impacts, while plants with costs of at least 1 percent but less than 3 percent of revenue have a higher chance of facing material economic impacts, and plants incurring costs of at least 3 percent of revenue have a still higher probability of material economic impacts.

[60] In using the year-by-year revenue values to develop an average over the data years, 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.

[61] AEO is published by the Energy Information Administration (EIA). AEO2013 contains projections and analysis of U.S. energy supply, demand, and prices through 2040; these projections are based on the EIA's National Energy Modeling System (NEMS).

[62] AEO2014 data were released after EPA completed these analyses. If AEO2014 electricity price projections were used, plant revenue values would have been approximately 5 percent higher.

[63] AEO2013 electricity price projections are in constant dollars; therefore, these adjustments yield 2015 revenue values in dollars of the year 2013.

4.2.2 Key Findings for Regulatory Options

Table 4-1 reports plant-level cost-to-revenue results by owner type and regulatory option. EPA estimates that for the majority of steam electric power plants, including those expected to incur zero compliance costs, costs would not exceed the 1 percent of revenue threshold under any of the five regulatory options. Ninety-three percent of plants have costs less than 1 percent of revenue under the final ELGs (Option D). Of the 8 plants that have costs 3 percent or greater of revenue under the final ELGs (Option D), two plants are owned by small entities (see *Chapter 8* for the definition of small entities).

Table 4-1: Plant-Level Cost-to-Revenue Analysis Results by Owner Type and Regulatory Option

Owner Type	Total Number of Plants[a]	Number of Plants with a Ratio of			
		0%[a,b]	≠0 and <1%	≥1 and <3%	≥3%
		Option A			
Cooperative	63	57	5	1	0
Federal	15	11	2	2	0
Investor-owned	681	622	56	3	0
Municipality	122	117	3	2	0
Nonutility	153	150	3	0	0
Other Political Subdivision	41	41	0	0	0
State	5	3	2	0	0
Total	**1,080**	**1,001**	**71**	**8**	**0**
		Option B			
Cooperative	63	57	3	3	0
Federal	15	11	2	2	0
Investor-owned	681	622	55	3	1
Municipality	122	117	2	3	0
Nonutility	153	150	3	0	0
Other Political Subdivision	41	41	0	0	0
State	5	3	2	0	0
Total	**1,080**	**1,001**	**67**	**11**	**1**
		Option C			
Cooperative	63	55	3	5	0
Federal	15	11	2	2	0
Investor-owned	681	596	74	10	1
Municipality	122	116	2	4	0
Nonutility	153	150	3	0	0
Other Political Subdivision	41	41	0	0	0
State	5	3	1	1	0
Total	**1,080**	**972**	**85**	**22**	**1**
		Option D			
Cooperative	63	52	4	6	1
Federal	15	11	2	2	0
Investor-owned	681	584	76	20	1
Municipality	122	110	3	5	4
Nonutility	153	147	3	3	0
Other Political Subdivision	41	39	0	0	2
State	5	3	0	2	0
Total	**1,080**	**946**	**88**	**38**	**8**

Table 4-1: Plant-Level Cost-to-Revenue Analysis Results by Owner Type and Regulatory Option

Owner Type	Total Number of Plants[a]	Number of Plants with a Ratio of			
		0%[a,b]	≠0 and <1%	≥1 and <3%	≥3%
		Option E			
Cooperative	63	52	3	7	1
Federal	15	11	2	2	0
Investor-owned	681	576	77	27	1
Municipality	122	109	4	5	4
Nonutility	153	146	4	3	0
Other Political Subdivision	41	38	1	0	2
State	5	3	0	2	0
Total	**1,080**	**935**	**91**	**46**	**8**

a. Plant counts are weighted estimates.

b. These plants already meet discharge requirements for the wastestreams controlled by a given regulatory option and are therefore not expected to incur compliance costs.
Source: U.S. EPA Analysis, 2015.

4.2.3 Uncertainties and Limitations

Despite EPA's use of the best available information and data available, including information provided to EPA by plant owners in the industry survey, this analysis of plant-level impacts has uncertainties and limitations, including:

- EPA assumed that the equipment installed to meet the limitations could reasonably be expected to operate for 20 years or more, based on a review of reported performance characteristics of the equipment components. 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.

- To the extent that actual 2015 plant revenue values differ from those estimated using EIA databases for 2007, 2008, 2009, 2010, 2011, and 2012, the impact of the final ELGs may be over- or under-estimated.

- As noted above, the zero cost pass-through assumption represents a worst-case scenario. To the extent that some steam electric power plants are able to pass at least some compliance costs to consumers through higher electricity prices, this analysis overstates the potential impact of the final ELGs on steam electric power plants.

- The compliance costs used in this analysis reflect anticipated unit retirements, conversions, and repowerings announced through August 2014 and scheduled to occur by 2023, and projected conversions to dry systems in response to the final CCR rule. EPA discusses the uncertainty of projecting changes in the plant universe and wastestreams in the *TDD*. To the extent that actual unit retirements, conversions, and repowerings at steam electric facilities differ from anticipated changes, total annualized compliance costs may differ from actual costs. Accounting for the effect of the CCR rule reduces compliance costs relative to those estimated based on the characteristics of plants reflected in the Steam Electric plant survey only. To quantify the uncertainty, EPA evaluated an alternate scenario that does not account for anticipated changes in response to the final CCR rule. The results of this sensitivity analysis are presented in *Appendix C* and show compliance costs for the final BAT and PSES (Option D) that are 51 percent higher, after-tax, than those presented in this section, resulting in 32 additional plants having costs that exceed 1 percent of revenue.

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

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 is different in concept from the plant-level impact analysis discussed in *Section 4.2*, but provides an equally useful understanding of the regulatory impact on entities; it adds particular insight on the impact of compliance requirements on those entities that own multiple plants.

EPA conducted this screening analysis at the *highest* level of *domestic* ownership, referred to as the "domestic parent entity" or "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.[64,65] As is the case with plant-level cost-to-revenue analysis (*Section 4.2*), the entity-level analysis presented in this chapter maintains the worst-case analytical assumption of no pass-through of compliance costs to electricity consumers.

4.3.1 Analysis Approach and Data Inputs

To assess the entity-level economic/financial impact of compliance requirements, EPA aggregated plant-level annualized after-tax compliance costs calculated in *Section 3.1.1* 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, EPA used cost-to-revenue ratios of 1 and 3 percent as markers of potential impact for this analysis. Similar to the assumptions made for the plant-level analysis, for this entity-level analysis the Agency assumed that entities incurring costs below 1 percent of revenue are unlikely to face significant economic impacts, while entities with costs of at least 1 percent but less than 3 percent of revenue have a higher chance of facing significant economic impacts, and entities incurring costs of at least 3 percent of revenue have a still higher probability of significant economic impacts.

EPA's plant-level analysis is based on a *sample* of the industry and supports specific estimates of (1) the total number of steam electric power plants and (2) the total compliance costs expected to be incurred by these plants. However, the plant-level analysis does not support precise estimates of the number of entities that own *all* steam electric power plants (*i.e.*, surveyed and non-surveyed plants (see *TDD*)). In addition, the sample does not support precise estimates of the number of steam electric power plants owned by a single entity, or the total of compliance costs across steam electric power plants owned by a single entity.

Therefore, for the entity-level analysis, EPA analyzed two cases based on the sample weights developed from the 2010 Questionnaire for the Steam Electric Power Generating Effluent Guidelines (industry survey; U.S. EPA, 2010a). These cases 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 a steam electric power plant. This entity-level cost-to-revenue analysis involved the following steps:

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

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

- Determining the parent entity,
- Determining the parent entity revenue,
- Estimating compliance costs at the level of the parent entity.

Determining the Parent Entity

EPA determined the highest level domestic parent entity for each surveyed steam electric power plant (681 plants) (for a discussion of the industry survey and the use of sample weights, see *TDD*).[66] To determine ownership, EPA relied primarily on the information from the industry survey. For plants for which the industry survey did not provide this information, the Agency used the 2012 EIA-860 and 2012 EIA-861 databases and corporate/financial websites (U.S. DOE, 2012b; U.S. DOE, 2012c).

Using the same sources, EPA determined each parent entity's shares of ownership in the surveyed steam electric power plants.

Determining Parent Entity Revenue

For each parent entity identified in the preceding step, EPA determined revenue values as follows:

- EPA used entity-level revenue values from the industry survey, if those were reported. For entities with values reported for more than one survey year (*i.e.*, 2007, 2008, and/or 2009), EPA used the average of reported values. For entities with values reported for only one survey year, EPA used the reported value.
- For public companies with no revenue values reported in the industry survey, EPA used revenue values from corporate or financial websites, if those values were available. To be consistent with the survey data, EPA tried to obtain revenue for at least one of the three survey years (*i.e.*, 2007, 2008, and/or 2009) and used the average of reported values. If revenue values were not reported on corporate/financial websites, the Agency used the 2007-2009 average revenue values from the EIA-861 database.
- For privately held companies with revenue values not reported in the industry survey, the Agency used corporate/financial websites. Again, to be consistent with the industry-survey data, EPA tried to obtain revenue for at least one of the three survey years (*i.e.*, 2007, 2008, and/or 2009) and used the average of reported values.

EPA restated entity revenue values in 2013 dollars using the GDP Deflator. For this analysis, the Agency assumed that these average revenue values are representative of revenues as of 2015. Although the entity-level revenue values might reasonably be expected to change by 2015 (*i.e.*, have increased or decreased relative to average revenue for the 2007 through 2009 period), 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 (*Section 3.1.1*). For the entity-level analysis, therefore, 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 2015 as they were at the time of the industry survey.

[66] EPA estimated costs for surveyed steam electric plants (*i.e.*, 681 plants). The remaining 399 plants are accounted for through application of sample weights to the surveyed plants, for a total universe of 1,080 plants.

EPA did not adjust the identity of the entities that own steam electric power plants to reflect sales and ownership changes that may have occurred since the industry survey was conducted. EPA is aware that some plants have changed ownership since the survey but EPA did not have the necessary data to revise ownership information accurately and consistently across the universe of plants. The analysis therefore assumes that any changes in plant ownership did not result in a substantively different profile of plant owners in terms of the types or sizes of the business entities with majority shares in the steam electric power plants analyzed.

Estimating Compliance Costs at the Level of the Parent Entity

Compliance costs for the regulatory options were directly attributable only to surveyed plants and were therefore able to be directly linked with the entities that own these plants only, not accounting for ownership of other steam electric power plants. To account for the parent entities of all 1,080 steam electric power plants, EPA therefore analyzed two approximate bounding cases based on the sample weights developed from the industry survey (see *TDD*). These cases 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) Assuming 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) Assuming 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. The two cases are laid out in more details below.

Case 1: Lower bound estimate of number of entities owning steam electric power plants; upper bound estimate of total compliance costs that an entity may incur.

For this case, EPA 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 entities, while tending to *maximize* the potential cost burden to any single entity. EPA grouped together all plants with a common parent entity and applied sample weights to the plant compliance costs. EPA calculated the entity-level compliance cost as:

$$CC_{entity} = \sum_{i} W_i \times CC_i$$

where:

CC_{entity} = entity-level compliance cost

CC_i = compliance cost for surveyed plant *i* owned by the entity

W_i = sample weight for surveyed plant *i* owned by the entity

As stated above, for the analysis of entity-level impacts, EPA calculated annualized after-tax compliance costs as a percentage of entity revenue. EPA judged that entities with annualized after-tax compliance cost of less than 1 percent of revenue are unlikely to face significant economic impacts. EPA identified entities as having a higher probability of significant economic impacts if annualized compliance cost were at least 3 percent of revenue.

Case 2: Upper bound estimate of number of entities owning steam electric power plants; lower bound estimate of total compliance costs that an entity may incur.

For this case, EPA inverted the prior assumption and assumed (1) that an entity owns only the surveyed plant(s) that it is known to own from the sample analysis and (2) that this pattern of ownership, observed for surveyed plants and their owning entities, extends over the plant population represented by the surveyed plants. This case minimizes the possibility of multi-plant ownership by a single entity and thus *maximizes* the count of entities, but also *minimizes* the potential cost burden to any single entity.

For each entity that owns one surveyed plant, no entity is assumed to own more than one steam electric power plant, and the analysis is straightforward: the entity owns one steam electric power plant and incurs compliance costs only for that plant. This configuration is assumed to exist as many as times as the plant's sample weight. Where the multiple plants owned by the same entity have the same sample weight, the analysis is also straightforward: the entity is assumed to own and incur the compliance costs of the identified surveyed plants, and the configuration is assumed to exist as many times as the uniform sample weight of the multiple plants.

Where the multiple plants owned by the same entity have the different sample weights, EPA accounted for the ownership of multiple surveyed plants by a single entity, but restricted the count of the multiple plants and their configuration of ownership for the entity-level cost analysis based on the sample weights of the individual surveyed plants. Specifically, the entity is assumed to exist on a sample-weighted basis as many times as the highest of the sample weights among the surveyed plants known to be owned by the entity. However, surveyed plants with a smaller sample weight, and their compliance costs, can be included in the total instances of ownership by the entity for only as many times as their sample weights. Otherwise, the total plant count implied in the entity analysis would exceed the total number of plants; correspondingly, the total of compliance costs accounted for in the entity level analysis would exceed the sample-based estimated total of plant compliance costs. For implementation, this means that all of the surveyed plants known to be owned by the same entity, and their compliance costs, can be included in the ownership configuration for only as many sample weighted instances as the smallest sample weight among the multiple plants owned by the entity. Once the sample weight of the smallest sample weight plant is "used up," a new multiple plant ownership is configured including only the costs for those plants with weights greater than the weight of the smallest sample weight plant. This configuration is assumed to exist for as many sample weighted instances as the difference between the lowest sample weight and the next higher sample weight among the plants owned by the entity. This process is repeated – with successive removal of the new lowest sample weight plant, and its compliance cost– as many times as necessary until only the highest sample weight plant remains in the ownership configuration.

For multi-plant entities, EPA grouped together all plants with a common parent entity from the surveys. For each parent entity in the analysis, entity-level compliance cost is:

$$CC_{entity} = \sum_{i} CC_i$$

where:

CC_{entity} = entity-level compliance cost

CC_i = compliance cost for the surveyed plant i, known to be owned by the entity

4.3.2 Key Findings for Regulatory Options

Table 4-2 summarizes the results from the entity-level impact analysis, assuming that non-surveyed plants are owned by the same entity that owns surveyed plants (Case 1) and the results from the entity impact analysis assuming that the non-surveyed plants are owned by different entities than those owning the surveyed plants (Case 2). *Table 4-2* shows the number of entities that incur costs in four ranges: no cost, non-zero costs less than 1 percent of an entity's revenue, at least 1 percent but less than 3 percent of revenue, and at least 3 percent of revenue.

EPA estimates that 243 and 507 parent entities own steam electric power plants under Case 1 and Case 2, respectively. EPA estimates that under Case 1, the majority of parent entities would incur annualized costs of less than 1 percent of revenues under all five regulatory options; 90 percent of entities have annualized costs less than 1 percent of revenue under the final ELGs (Option D).[67] Case 2 shows the same number of entities with cost-to-revenue ratios greater than zero; 92 percent of entities have costs less than 1 percent of revenue ranges under the final ELGs (Option D).

Overall, this screening-level analysis shows that the entity-level compliance costs are low in comparison to the entity-level revenues; very few entities are likely to face economic impacts at any level.

Table 4-2: Entity-Level Cost-to-Revenue Analysis Results

	Case 1: Lower bound estimate of number of entities owning steam electric power plants						Case 2: Upper bound estimate of number of entities owning steam electric power plants					
	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[b]**		**0%[a]**	**≠0 and <1%**	**≥1 and <3%**	**≥3%**	**Unknown[b]**
Option A												
Cooperative	29	22	6	0	0	1	49	39	6	0	0	3
Federal	2	0	1	0	0	1	4	2	1	0	0	1
Investor-owned	97	69	25	0	0	3	244	209	25	0	0	10
Municipality	65	60	4	1	0	0	101	96	4	1	0	0
Nonutility	36	26	2	0	0	8	77	62	2	0	0	13
Other Political Subdivision	12	11	0	0	0	1	30	27	0	0	0	3
State	2	1	1	0	0	0	2	1	1	0	0	0
Total	**243**	**189**	**39**	**1**	**0**	**14**	**507**	**437**	**39**	**1**	**0**	**30**
Option B												
Cooperative	29	22	6	0	0	1	49	39	6	0	0	3
Federal	2	0	1	0	0	1	4	2	1	0	0	1
Investor-owned	97	69	25	0	0	3	244	209	25	0	0	10
Municipality	65	60	3	2	0	0	101	96	3	2	0	0
Nonutility	36	26	2	0	0	8	77	62	2	0	0	13
Other Political Subdivision	12	11	0	0	0	1	30	27	0	0	0	3
State	2	1	1	0	0	0	2	1	1	0	0	0
Total	**243**	**189**	**38**	**2**	**0**	**14**	**507**	**437**	**38**	**2**	**0**	**30**
Option C												
Cooperative	29	19	9	0	0	1	49	36	9	0	0	3
Federal	2	0	1	0	0	1	4	2	1	0	0	1
Investor-owned	97	62	32	0	0	3	244	202	32	0	0	10
Municipality	65	59	3	2	1	0	101	95	3	2	1	0
Nonutility	36	26	2	0	0	8	77	62	2	0	0	13

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

Table 4-2: Entity-Level Cost-to-Revenue Analysis Results

Entity Type	Case 1: Lower bound estimate of number of entities owning steam electric power plants						Case 2: Upper bound estimate of number of entities owning steam electric power plants					
	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[b]		0%[a]	≠0 and <1%	≥1 and <3%	≥3%	Unknown[b]
Other Political Subdivision	12	11	0	0	0	1	30	27	0	0	0	3
State	2	1	1	0	0	0	2	1	1	0	0	0
Total	**243**	**178**	**48**	**2**	**1**	**14**	**507**	**426**	**48**	**2**	**1**	**30**
Option D												
Cooperative	29	17	10	1	0	1	49	34	10	1	0	3
Federal	2	0	1	0	0	1	4	2	1	0	0	1
Investor-owned	97	61	32	1	0	3	244	201	32	1	0	10
Municipality	65	53	6	4	2	0	101	89	6	4	2	0
Nonutility	36	25	2	1	0	8	77	61	2	1	0	13
Other Political Subdivision	12	9	2	0	0	1	30	25	2	0	0	3
State	2	1	0	1	0	0	2	1	0	1	0	0
Total	**243**	**166**	**53**	**8**	**2**	**14**	**507**	**414**	**53**	**8**	**2**	**30**
Option E												
Cooperative	29	17	9	2	0	1	49	34	9	2	0	3
Federal	2	0	1	0	0	1	4	2	1	0	0	1
Investor-owned	97	59	34	1	0	3	244	199	34	1	0	10
Municipality	65	53	5	5	2	0	101	89	5	5	2	0
Nonutility	36	25	2	1	0	8	77	61	2	1	0	13
Other Political Subdivision	12	9	2	0	0	1	30	25	2	0	0	3
State	2	1	0	1	0	0	2	1	0	1	0	0
Total	**243**	**164**	**53**	**10**	**2**	**14**	**507**	**412**	**53**	**10**	**2**	**30**

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

b. EPA was unable to determine revenues for 14 and 30 parent entities under Case 1 and Case 2, respectively.
Source: U.S. EPA Analysis, 2015.

4.3.3 Uncertainties and Limitations

Despite EPA's use of the best available information and data available, including information provided to EPA by plant owners in the industry survey, this analysis of entity-level impacts has uncertainties and limitations, including:

- The entity-level revenue values obtained from the industry survey, corporate and financial websites, or EIA databases are for 2007, 2008, and/or 2009. To the extent that actual 2015 entity revenue values are different, on a constant dollar basis, from those estimated using data for 2007, 2008, and/or 2009, 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. 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. To the extent that some entities are able to pass at least some compliance costs to consumers through higher electricity prices, this analysis overstates the potential entity-level impact of the final ELGs.
- The compliance costs used in this analysis reflect anticipated unit retirements, conversions, and repowerings announced through August 2014 scheduled to occur by 2023, and projected conversions to dry systems in response to the final CCR rule. To the extent that actual unit retirements, conversions, and repowerings at steam electric power plants differ from anticipated changes, total annualized compliance costs may differ from actual costs. Accounting for the effect of the CCR rule reduces compliance costs relative to those estimated based on the characteristics of plants reflected in the industry survey. To quantify the uncertainty, EPA evaluated an alternate scenario that ignores changes due to the CCR rule. The results of this scenario are presented in *Appendix C* and show compliance costs for the final BAT and PSES (Option D) that are 51 percent higher than those presented above. These higher compliance costs translate in slightly higher, but still small, entity-level impacts, with 6 additional entities having compliance costs that exceed 1 percent of revenue, out of the total 243 to 507 entities that own steam electric power plants.

5 Assessment of the Impact of the Final ELG Options in the Context of National Electricity Markets

In analyzing the impacts of various regulatory actions affecting the electric power sector over the last decade, 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 final ELG options, EPA used an updated version of this same analytic system: Integrated Planning Model Version 5.13 MATS (IPM V5.13) (U.S. EPA, 2013a), summarized in *Appendix E: Overview of the Integrated Planning Model*.[68]

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 EPA's assessment of the economic achievability of the final ELGs under CWA Sections 301(b)(2)(A) and 304(b)(2) and determine whether the final ELGs would result in any capacity retirements (full or partial plant closures). It also provides insight on the impact of the final rule on the overall electricity market, including to assess whether the rule may significantly the energy supply, distribution or use under Executive Order 13211 (see *Section 10.6*). EPA used the screening-level analyses described above to inform the selection of regulatory options to be analyzed using IPM. In allocating resources to analytical effort, EPA chose to run IPM in a phased approach, starting with Option D and then Option B, with the notion to proceed if additional model runs were warranted. EPA presents results of these Option B and D runs in this section. As a sensitivity analysis on the role of EPA's *RCRA Final Rule Regulating Coal Combustion Residual Landfills and Surface Impoundments At Coal-Fired Electric Utility Power Plant*s ("the CCR Rule") on steam electric facilities' costs to meet the ELG limitations, EPA also ran IPM using a worst-case version of Option D costs without any assumed changes to the wastestreams generated by the plants as a result of the CCR rule, *i.e.*, ignoring any changes prompted by the CCR rule that would reduce the cost of meeting the ELG limitations. *Appendix C* presents results of this alternate scenario.

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 higher generation costs for steam electric units due to the final ELGs. 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 2013* (AEO2013), whereas the screening-level analyses discussed in other chapters of this report assume that plants would generate approximately the same quantity of electricity in 2015 as they did on average during 2007-2012.

Increases in electricity production costs and potential reductions 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

[68] For more information on IPM, see http://www.epa.gov/airmarkets/progsregs/epa-ipm/toxics.html.

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.

EPA's use of IPM V5.13 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 *Appendix E,* 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 questions at the plant, regional, and national levels. In the past, 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 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, 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, and environmental constraints. Demand-side constraints include reserve margin constraints and minimum system-wide load requirements.

The final difference between 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, EPA used an electricity market "base case" that includes market-level impacts of the proposed CPP rule,[69] the final CWA section 316(b) rule, promulgated in July 2014, and the final CCR rule, promulgated in December 2014, among others.

In analyzing the effect of final ELGs in context of the IPM v.5.13 base case, 316(b) rule, CCR rule and anticipated CPP rule impacts, EPA specified additional fixed and variable costs that are expected to be incurred by steam electric power plants and generating units to meet effluent limitations and standards. EPA ran IPM to determine the dispatch of electricity generating units that will meet projected demand at the lowest costs subject to the same constraints as those present in this analysis baseline.

This chapter is organized as follows:

- *Section 5.1* summarizes the key inputs to IPM for performing the analyses of the final ELGs and the key outputs reviewed as indicators of the effect of the regulatory options.
- *Section 5.2* describes the regulatory options analyzed in the market model analysis and how these options map to the broader set of regulatory options that EPA analyzed for the final ELGs.
- *Section 5.3* provides the findings from the market model analysis.
- *Section 5.5* identifies key uncertainties and limitations in the market model analysis.

[69] See memorandum in the docket for a comparison of the proposed and final CPP rules and a discussion of the implications of including the proposed CPP rule in the baseline as compared to the final CPP rule EPA promulgated on August 3, 2015. (DCN SE05983)

5.1 Model Analysis Inputs and Outputs

To assess the impact of the final ELGs, EPA compared each of two policy runs (post-compliance cases corresponding to Option B and Option D) to an IPM V5.13 projection of electricity markets and plant operations given EPA Base Case v.5.13 projections that includes the modeled effects of the 316(b), CPP, and CCR rules.

5.1.1 Analysis Years

As discussed in *Appendix E*, IPM V5.13 models the electric power market over the 39-year period from 2016 to 2054. Within this total analysis period, EPA looked at shorter IPM analysis periods (run-year windows)[70] to assess the market-level effect of the final ELGs. To assess the impact of the final ELGs during the period in which steam electric power plants are implementing the control technologies (the technology implementation period) – the *short-term* effects analysis – EPA used results reported for the 2020 and 2025 IPM run years. As discussed in *Chapter 3: Compliance Costs*, steam electric power plants are estimated to implement control technologies to meet the final ELG requirements during a 5-year window of 2019 through 2023. Because this technology implementation window primarily falls within the time periods captured by the 2020 run year (*i.e.*, 2019-2022), EPA judges that 2020 is an appropriate run year to capture regulatory effects during the transition. Because of the potential increase in electricity production costs at steam electric power plants due to compliance, it is important to examine market-level effects during the technology implementation period. Specifically, in seeking to minimize the cost of meeting electricity demand, IPM will tend to shift production away from steam electric power plants that incur relatively higher variable costs, and will shift production to either non-steam plants, which incur no compliance costs, or to steam electric power plants that incur relatively lower compliance costs. Any of these changes – whether a simple increase in production costs for previously dispatched units or changes in the profile of generating unit dispatch – necessarily mean increased total costs for electricity generation, compared to the pre-regulation baseline.

To assess the *longer term* effect of the final ELGs on electricity markets during the period *after* technology implementation by *all* steam electric power plants – the *steady state* post-compliance period – EPA analyzed results reported for the IPM 2030 run year.[71] As discussed in *Chapter 3*, under the regulatory option specifications considered for this analysis, this *steady state* period is expected to begin in the last year of the technology implementation window, *i.e.*, 2023, and continue into the future. The 2023 analysis year is captured in the IPM 2025 run year. Because the next model run year, 2030, captures calendar years (*i.e.*, 2028-2033) that fall outside the technology implementation window of 2019 through 2023, EPA judges that 2030 is an appropriate run year to capture steady-state regulatory effects. Effects that may occur during the post-compliance "steady state" include potential *permanent* losses in generating capacity from early retirement (closure) of generating units, *long-term* increases in electricity production costs due to higher operating expenses, and permanent reduction in electric generating capability and production efficiency at steam electric power plants, and, as described above, the need to dispatch other, potentially higher production cost, generating units to offset losses in electric generating capacity.

[70] Due to the highly data- and calculation-intensive computational procedures required for the IPM dynamic optimization algorithm, IPM is run only for a limited number of years. Run years are selected based on analytical requirements and the necessity to maintain a balanced choice of run years throughout the modeled time horizon. Each run year represents other adjacent years in addition to the run year itself.

[71] The 2020 run year accounts for costs recognized within the period of 2019-2022. Some O&M costs start after 2024 (*e.g.*, 5-year fixed O&M costs begin five years after the technology implementation year). By the 2030 run year, all costs have been recognized by all plants.

The two run years provide different views of the industry over time, accounting for changes in electricity demand and generation mix, and for the effects of compliance with other regulatory requirements included in IPM v.5.13.

5.1.2 Key Inputs to IPM V5.13 for the Final ELGs Market Model Analysis

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 16,282 generating units at 5,539 plants.[72,73] EPA estimated that up to 195 steam electric power plants may incur compliance costs under any of the final ELG options, based on the costing methodologies described in the *TDD*; 194 of these 195 plants are modeled in IPM (U.S. EPA, 2015c).[74] However, since the plant not represented in IPM does not get cost under the two options EPA analyzed in IPM (Options B and D), the exclusion of this plant does not affect the total compliance costs input into the model in the analyses described below.

These input cost categories are as follows:

- *Capital cost* inputs, which include the cost of compliance technology equipment, installation, site preparation, construction, and other upfront, non-annually recurring outlays associated with compliance with regulatory options. Capital costs are specified in terms of the expected useful service life of the capital outlay. All compliance technologies for the regulatory options are assumed to have a useful life of 20 years.

  In the Market Model Analysis, these outlays are converted into a constant annual charge using IPM's conventional frameworks for recognition of capital outlays over the useful life of the technology.

- *Initial one-time cost* inputs (apart from capital costs, above), if applicable, consist of a one-time cost to close bottom ash system. Steam electric power plants are expected to incur these costs only once.[75]

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[72] IPM includes 672 of the 681 steam electric power plants that provided data to EPA in the industry survey. EPA characterized the 681 steam electric plants that completed the industry survey (surveyed plants) and used sample weights to characterize the remaining 399 plants, for a total universe of 1,080 steam electric plants. The *TDD* details the methodology EPA used to identify steam electric plants, assess compliance technologies, and develop plant-level cost estimates for each regulatory option.

[73] Nine steam electric surveyed plants are not modeled in IPM. These plants include two plants located in Alaska and six plants located in Hawaii (and thus not included in IPM), and one plant excluded from the IPM baseline as the result of custom adjustments made by ICF based on the proprietary information about existing power-plant universe.

[74] For the purpose of this analysis, EPA used compliance costs that do not account for projected retirements resulting from the proposed CPP rule. In effect, generating units that are projected to retire in the IPM base case may still receive costs under the ELG option, but the plant will not incur these costs if the units are projected to retire in the policy case. Note that EPA did not assign costs to plants that have announced conversions or retirements of their steam electric units through 2023 (see TDD). However, 57 of these generating units are included in IPM and projected to continue to generate electricity over the period of analysis. Omitting compliance costs for these plants may affect the model projections by making the generating units relatively more cost effective. EPA expects any resulting distortion in the modeled generation dispatch to be small, however, since the affected units have an aggregate generating capacity of 9,783 MW (1.2 percent of IPM's generating capacity) and generated only 39,979 MWh (1.2 percent of total generation) in the 2025 run year.

[75] Because steam electric plants are expected to incur this cost only once, for the purpose of cost and economic impact analyses, this cost is annualized over the analysis period. Because the Market Model Analysis covers 43 years, to analyze these costs in IPM, they were annualized over 43 years.

For the purpose of this Market Model Analysis, these costs are also converted into a constant annual charge.

- *Annual Fixed O&M cost* inputs, if applicable, are expressed in dollars per kilowatt (kW) of capacity per year. As discussed in *Chapter 3*, fixed O&M costs include regular annual monitoring costs and oil storage costs.
- *Annual Variable O&M cost* inputs, if applicable, are expressed in dollars per kilowatt hour (kWh) of generation. Annual variable O&M costs include annual operating labor, maintenance labor and materials, additional electricity required to operate wastewater treatment systems, chemicals, oil conveyance operation and maintenance, ash disposal operation and maintenance, and savings from not operating and maintaining ash/FGD pond systems.

In addition to these initial one-time and annual outlays, certain other O&M and/or capital costs are expected to be incurred on a non-annual, periodic basis:

- *3-Yr Fixed O&M cost* inputs, if applicable, include mechanical drag system (MDS) chain replacement costs that plants are expected to incur every three years, beginning three years after the technology implementation year. For the Market Model Analysis, these costs are spread over three years to calculate costs on a per year basis and are expressed in dollars per kilowatt hour (kWh) of generation.
- *5-Yr Fixed O&M cost* inputs, if applicable, include remote MDS chain replacement costs that plants are expected to incur every five years, beginning five years after the technology implementation year. For the Market Model Analysis, these costs are spread over five years to calculate costs on a per year basis and are expressed in dollars per kilowatt hour (kWh) of generation.
- *6-Yr fixed O&M costs*, if applicable, include mercury analyzer operating and maintenance costs that plants are expected to incur every six years, beginning in the technology implementation year. For the Market Model Analysis, these costs are spread over six years to calculate costs on a per year basis and are expressed in dollars per kilowatt hour (kWh) of generation.
- *10-Yr Fixed O&M cost* inputs, if applicable, include capital costs for water trucks, and savings from not needing to periodically maintain ash/flue gas desulfurization (FGD) pond systems. Steam electric power plants are expected to purchase water trucks every 10 years, beginning in the technology implementation year, and incur savings every 10 years, beginning 5 years after technology implementation. For the Market Model Analysis, these costs are spread over 10 years to calculate costs on a per year basis and are expressed in dollars per kilowatt hour (kWh) of generation.

In addition to specifying these cost elements, the model assigns a technology implementation year to each plant. EPA used the same years discussed in *Chapter 3*, resulting in control technologies being implemented at modeled steam electric power plants during the period of 2019 through 2023.

Because the Market Model Analysis is performed at the level of the individual boiler and/or generating unit, plant-level costs had to be allocated to boilers/generating units. EPA allocated plant-level costs across steam generating units (boilers and generators) based on electricity generating capacity.

As noted above, IPM modelers used the inputs above to calculate the net present value of annualized costs using IPM's conventional framework for recognizing costs incurred over time.[76]

[76] 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

New Capacity

Steam electric generating units that meet the definition of a "new source" would be required to meet the final New Source Performance Standards (NSPS) and Pretreatment Standards for New Sources (PSNS). As discussed in *Chapter 3*, the final ELGs establish NSPS or PSNS based on the suite of technologies identified in Option F. IPM includes the option to build additional generating capacity as an option for meeting future electricity demand at the lowest cost. EPA included incremental costs of the final rule as input to IPM to allow these costs to be considered in the decision of whether to build new capacity.[77]

Compliance costs for these new units include capital costs, annual fixed and variable O&M costs, 6-Yr fixed O&M costs, and 10-Yr O&M savings from not needing to periodically maintain ash/FGD pond systems. For the IPM analysis, EPA expressed fixed and variable (annual and non-annual) O&M costs in the same way as that described earlier for existing units – *i.e.*, in dollars per kW and kWh, respectively – and expressed capital cost in dollars per kW (see *Appendix E*).[78] See *TDD* for a detailed discussion on estimation of new capacity and associated compliance costs.

Note that IPM does not project new coal-fired capacity in either the base case or the two policy cases EPA analyzed in IPM.

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

IPM V5.13 provides outputs for the NERC regions that lie within the continental United States. As described above, IPM V5.13 does not analyze electric power operations in Alaska and Hawaii because these states' electric power operations are not interconnected to the continental U.S. power grid.

IPM V5.13 generates a series of outputs at different levels of aggregation (model plant, region, and nation). The economic analysis for the final ELGs used a subset of the available IPM output. For each model run (baseline case and each analyzed regulatory option) and for the run years indicated above, the following model outputs were generated:

- *Capacity* – Capacity is a measure of the ability to generate electricity. This output measure reflects the summer net dependable capacity of all generating units at the plant. The model differentiates between existing capacity and new capacity additions.

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 treatment of capital costs ensures both realism and consistency in accounting for the full cost of each of the investment options in the model. The cost components appearing in IPM's objective function represent the composite cost over all years in the planning horizon rather than just the cost in the individual model run years. This permits the model to capture more accurately the escalation of the cost components over time*" (Chapter 2 in U.S. EPA, 2010c).

[77] EPA used compliance costs developed for Option E (as compared to the final selected option, Option F). Costs for Option E are lower than for Option F but the differences are not consequential since, as described above, IPM does not project new coal-fired capacity in either the base case or the policy case.

[78] EPA used compliance costs for a 600 MW unit, consistent with assumptions used in IPM to model new coal-fired capacity. To express variable O&M costs in dollars per kWh, EPA assumed capacity utilization of 330 hours/year. For details on methodology to estimate compliance costs for new sources, see *TDD*.

- *Early Retirements* – IPM models two types of plant closures: closures of nuclear plants as a result of license expiration and economic closures as a result of negative net present value of future operation. This analysis considers only economic closures in assessing the impacts of the final ELGs.
- *Energy Price* – The average annual wholesale electricity price received for the sale of electricity.
- *Capacity Price* – The premium over energy prices (above) received by plants operating in peak hours during which system load approaches available capacity; capacity price is part of the total wholesale electricity price. The capacity price is the premium required to stimulate new market entrants to construct additional capacity, cover costs, and earn a return on their investment. This price manifests as short term price spikes during peak hours and, in long-run equilibrium, need be only so large as is required to justify investment in new capacity.
- *Generation* – The amount of electricity produced by each plant that is available for dispatch to the transmission grid ("net generation"). IPM provides summer, winter and total annual generation.
- *Fuel Costs* – The cost of fuel consumed in the generation of electricity. IPM provides summer, winter and total annual fuel costs.
- *Variable Operation and Maintenance (VOM) Costs* – Non-fuel O&M costs that vary with the level of generation, *e.g.*, cost of consumables, including water, lubricants, and electricity. IPM provides summer, winter and total annual VOM costs. In the post-compliance cases, variable O&M costs also include the variable share of the costs of meeting the ELG limitations.
- *Fixed Operation and Maintenance (FOM) Costs* – O&M costs that do not vary with the level of generation, *e.g.*, labor costs and capital expenditures for maintenance. In the post-compliance cases, fixed O&M costs also include the fixed share of the final ELG compliance costs, notably annualized capital costs.
- *Capital Costs* – The cost of construction, equipment, and capital. Capital costs include costs associated with investment in new equipment, *e.g.*, the replacement of a boiler or condenser, implementation of technologies to meet various regulatory requirements.
- *Air Emissions* – IPM models carbon dioxide (CO_2), nitrogen oxide (NOx), sulfur dioxide (SO_2), mercury (Hg), and hydrogen chloride (HCL) emissions resulting from electricity generation.

Comparison of these outputs for the baseline and post-compliance cases provides insight into the effect of the final ELG options on steam electric power plants and the broader electric power markets.[79]

5.2 Regulatory Options Analyzed

EPA selected two of the five regulatory options analyzed elsewhere in this document to bracket the reasonable range of costs and impacts across regulatory options under consideration: Market Model Analysis Option B and Market Model Analysis Option D (for description of the regulatory options see *Chapter 1: Introduction*). These Market Model Analysis Options align *approximately* with regulatory Options B and D, respectively, described in *Chapter 1* and discussed elsewhere in this report. Market Model Analyses for Options B and D do not include compliance technology costs assigned to one steam electric facility, which were determined only after IPM analysis of these options had been completed. Omitted costs are a very small share of total costs and are not expected to affect the overall results of the analysis.

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

Appendix C describes results of a third IPM analysis designed as a sensitivity analysis on EPA's projections of the impacts of the CCR Final Rule on wastestreams generated by steam electric power plants. This sensitivity analysis represents a worst-case variant on Option D wherein plants incur compliance costs irrespective of any changes they may have implemented in response to the final CCR rule that would have reduced these costs.

The two options analyzed in IPM – Option B and Option D – provide insight on the market impacts of the regulatory options EPA analyzed for this action, with Option D results providing insight on the likely impacts of the final rule. The impacts of Option C are expected to lie between those of Options B and D. Option E is more stringent than either of the two options analyzed in IPM; as such, the impacts of Option E (if that option had been specified for BAT and PSES) would be expected to be greater than those of Option D.

5.3 Findings from the Market Model Analysis

The impacts of the analysis options are assessed as the difference between key economic and operational impact metrics that compare the post-compliance cases to the pre-ELG baseline case. This section presents two sets of analysis:

- *Analysis of long-term regulatory impacts*: As discussed earlier, to assess the long-term impact of the final ELGs, EPA compared baseline and policy IPM results reported for 2030. These results provide insight on the effect of the final ELGs during the steady state period of post-compliance operations. The Agency conducted the long-term impact analysis for the entire electricity market and for steam electric power plants specifically.
- *Analysis of short-term regulatory impacts*: EPA also presents a subset of results for the 2020 model run year, which captures regulatory impacts during the transition to the revised effluent limitations and standards. The Agency conducted this analysis for the entire electricity market.

5.3.1 Analysis Results for the Year 2030 – To Reflect Steady State, Post-Compliance Operations

In these results which reflect conditions in the period of 2028 through 2033, all plants are expected to meet the revised effluent limits and standards associated with each analyzed regulatory options. EPA considered impact metrics of interest at three levels of aggregation:

- Impact on national and regional electricity markets,
- Impact on steam electric power plants as a group, and
- Impact on individual steam electric power plants.

Impact on National and Regional Electricity Markets

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

- *Changes in available capacity*: This measure analyzes changes in the capacity available to generate electricity. A long-term reduction in available capacity may result from partial or full closures of steam electric power plants. For this impact measure, EPA distinguished between existing capacity and new capacity additions. Under this measure, EPA also analyzed capacity closures. Only capacity that is projected to remain operational in the baseline case but is closed in the post-compliance case is considered a closure attributable to the final ELGs. 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 avoided closures in which a unit or plant that is estimated to close in the baseline is estimated to continue operation in the post-compliance case. Avoided closures may occur among plants that incur no compliance costs or for which compliance costs are low relative to other steam electric power plants.

- *Changes in the price of electricity*: This measure considers changes in regional wholesale electricity prices – the sum of energy and capacity prices – as a result of the regulatory options. In the long term, electricity prices may change as a result of increased generation costs at steam electric power plants or due to generating unit and/or plant closures. For this analysis, EPA combined both components of the estimated electricity price – *i.e.*, energy price and capacity price – into a single energy-unit equivalent price (*i.e.*, $/MWh of energy).
- *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. 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 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 final ELGs may increase generation costs and make electricity generated by some steam electric units more 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.

Table 5-1 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.

Differences in the relative magnitude of impacts across the NERC regions largely reflect regional differences in ELG compliance costs (*i.e.*, number of plants incurring costs and the magnitude of these costs) and the generation mix.

Table 5-1: Impact of Regulatory Options on National and Regional Markets at the Year 2030[a]

Economic Measures (all dollar values in $2013)	Baseline Value	Option B			Option D		
		Value	Difference	% Change	Value	Difference	% Change
National Totals							
Total Capacity (GW)	1,021	1,020	-1	-0.1%	1,021	0	0.0%
Existing			-1	-0.1%		-1	-0.1%
New Additions			0	0.0%		1	0.1%
Early Retirements			1	0.1%		1	0.1%
Electricity Prices ($/MWh)	NA	NA	NA	NA	NA	NA	NA
Generation (TWh)	4,050	4,049	0	0.0%	4,049	-1	0.0%
Costs ($Millions)	$198,219	$198,494	$275	0.1%	$198,970	$752	0.4%
Fuel Cost	$104,850	$104,801	-$49	0.0%	$104,846	-$3	0.0%
Variable O&M	$13,466	$13,557	$91	0.7%	$13,669	$204	1.5%
Fixed O&M	$57,563	$57,741	$178	0.3%	$58,013	$450	0.8%
Capital Cost	$22,340	$22,396	$55	0.2%	$22,441	$101	0.5%
Variable Production Cost ($/MWh)	$29.21	$29.23	$0.01	0.0%	$29.27	$0.06	0.2%
CO_2 Emissions (Million Metric Tons)	1,679	1,679	0	0.0%	1,677	-2	-0.1%
Hg Emissions (Tons)	7	7	0	0.0%	7	0	0.0%
NOx Emissions (Million Tons)	1	1	0	-1.5%	1	0	-0.8%
SO_2 Emissions (Million Tons)	1	1	0	0.1%	1	0	-0.1%
HCL Emissions (Million Tons)	0	0	0	0.0%	0	0	-0.5%
Florida Reliability Coordinating Council (FRCC)							
Total Capacity (GW)	62	62	0	0.0%	62	0	0.0%
Existing			0	0.0%		0	0.0%
New Additions			0	0.0%		0	0.0%
Early Retirements			0	0.0%		0	0.0%
Electricity Prices ($/MWh)	$67.20	$67.18	-$0.02	0.0%	$67.25	$0.05	0.1%
Generation (TWh)	246	246	0	0.0%	246	0	0.0%
Costs ($Millions)	$15,462	$15,462	$0	0.0%	$15,479	$17	0.1%
Fuel Cost	$10,635	$10,630	-$4	0.0%	$10,645	$10	0.1%
Variable O&M	$806	$806	$0	0.0%	$806	$0	0.0%
Fixed O&M	$2,377	$2,383	$5	0.2%	$2,384	$7	0.3%
Capital Cost	$1,644	$1,643	-$1	-0.1%	$1,643	-$1	0.0%
Variable Production Cost ($/MWh)	$46.51	$46.50	-$0.02	0.0%	$46.56	$0.04	0.1%
CO_2 Emissions (Million Metric Tons)	82	82	0	0.0%	82	0	0.0%
Hg Emissions (Tons)	0	0	0	0.0%	0	0	0.0%
NOx Emissions (Million Tons)	0	0	0	-0.7%	0	0	0.0%
SO_2 Emissions (Million Tons)	0	0	0	0.1%	0	0	0.1%
HCL Emissions (Million Tons)	0	0	0	-0.9%	0	0	-0.7%
Midwest Reliability Organization (MRO)							
Total Capacity (GW)	65	65	0	0.1%	65	0	-0.3%
Existing			0	0.1%		0	-0.3%
New Additions			0	0.0%		0	0.0%
Early Retirements			0	-0.1%		0	0.3%
Electricity Prices ($/MWh)	$58.47	$58.72	$0.25	0.4%	$58.63	$0.15	0.3%
Generation (TWh)	247	247	1	0.3%	247	1	0.2%
Costs ($Millions)	$10,683	$10,732	$48	0.5%	$10,772	$89	0.8%
Fuel Cost	$4,729	$4,754	$25	0.5%	$4,745	$16	0.3%
Variable O&M	$1,012	$1,018	$6	0.6%	$1,033	$21	2.1%
Fixed O&M	$3,648	$3,657	$9	0.2%	$3,687	$39	1.1%
Capital Cost	$1,294	$1,303	$9	0.7%	$1,306	$12	1.0%
Variable Production Cost ($/MWh)	$23.28	$23.34	$0.06	0.3%	$23.37	$0.09	0.4%

Table 5-1: Impact of Regulatory Options on National and Regional Markets at the Year 2030[a]

Economic Measures (all dollar values in $2013)	Baseline Value	Option B			Option D		
		Value	Difference	% Change	Value	Difference	% Change
CO_2 Emissions (Million Metric Tons)	138	139	0	0.3%	139	0	0.3%
Hg Emissions (Tons)	1	1	0	0.1%	1	0	0.2%
NOx Emissions (Million Tons)	0	0	0	-0.3%	0	0	0.5%
SO_2 Emissions (Million Tons)	0	0	0	0.3%	0	0	0.5%
HCL Emissions (Million Tons)	0	0	0	0.0%	0	0	0.1%
Northeast Power Coordinating Council (NPCC)							
Total Capacity (GW)	67	67	0	0.0%	67	0	0.0%
Existing			0	0.0%		0	0.0%
New Additions			0	0.0%		0	0.0%
Early Retirements			0	0.0%		0	0.0%
Electricity Prices ($/MWh)	$67.67	$67.70	$0.02	0.0%	$67.76	$0.09	0.1%
Generation (TWh)	217	217	0	0.0%	217	0	-0.1%
Costs ($Millions)	$10,732	$10,741	$9	0.1%	$10,730	-$2	0.0%
Fuel Cost	$5,548	$5,547	-$2	0.0%	$5,540	-$9	-0.2%
Variable O&M	$448	$448	$0	0.0%	$448	$0	0.0%
Fixed O&M	$3,792	$3,793	$1	0.0%	$3,793	$1	0.0%
Capital Cost	$943	$952	$9	0.9%	$949	$6	0.6%
Variable Production Cost ($/MWh)	$27.60	$27.58	-$0.02	-0.1%	$27.58	-$0.02	-0.1%
CO_2 Emissions (Million Metric Tons)	43	43	0	0.0%	43	0	-0.1%
Hg Emissions (Tons)	0	0	0	0.0%	0	0	0.1%
NOx Emissions (Million Tons)	0	0	0	-2.6%	0	0	0.3%
SO_2 Emissions (Million Tons)	0	0	0	0.4%	0	0	0.9%
HCL Emissions (Million Tons)	0	0	0	0.2%	0	0	0.4%
ReliabilityFirst Corporation (RFC)							
Total Capacity (GW)	209	209	0	0.1%	210	0	0.2%
Existing			0	0.0%		0	0.0%
New Additions			0	0.1%		0	0.2%
Early Retirements			0	0.0%		0	0.0%
Electricity Prices ($/MWh)	$61.17	$61.26	$0.09	0.1%	$61.46	$0.29	0.5%
Generation (TWh)	924	922	-2	-0.2%	923	0	0.0%
Costs ($Millions)	$47,805	$47,851	$46	0.1%	$48,129	$324	0.7%
Fuel Cost	$22,395	$22,331	-$64	-0.3%	$22,387	-$8	0.0%
Variable O&M	$3,200	$3,221	$21	0.7%	$3,283	$83	2.6%
Fixed O&M	$16,203	$16,277	$74	0.5%	$16,418	$215	1.3%
Capital Cost	$6,007	$6,023	$16	0.3%	$6,042	$35	0.6%
Variable Production Cost ($/MWh)	$27.71	$27.71	$0.00	0.0%	$27.80	$0.09	0.3%
CO_2 Emissions (Million Metric Tons)	462	462	-1	-0.2%	461	-1	-0.2%
Hg Emissions (Tons)	2	2	0	-0.1%	2	0	-0.3%
NOx Emissions (Million Tons)	0	0	0	-0.5%	0	0	-0.3%
SO_2 Emissions (Million Tons)	0	0	0	0.0%	0	0	0.2%
HCL Emissions (Million Tons)	0	0	0	-0.1%	0	0	-0.2%
Southeast Electric Reliability Council (SERC)							
Total Capacity (GW)	253	252	-1	-0.4%	254	0	0.0%
Existing			-1	-0.4%		0	-0.1%
New Additions			0	0.0%		0	0.1%
Early Retirements			1	0.4%		0	0.1%
Electricity Prices ($/MWh)	$61.49	$61.52	$0.03	0.0%	$61.63	$0.14	0.2%
Generation (TWh)	1,104	1,104	0	0.0%	1,102	-1	-0.1%

Table 5-1: Impact of Regulatory Options on National and Regional Markets at the Year 2030[a]

Economic Measures (all dollar values in $2013)	Baseline Value	Option B			Option D		
		Value	Difference	% Change	Value	Difference	% Change
Costs ($Millions)	$54,938	$55,108	$171	0.3%	$55,186	$248	0.5%
Fuel Cost	$30,351	$30,378	$26	0.1%	$30,363	$11	0.0%
Variable O&M	$3,576	$3,638	$62	1.7%	$3,656	$80	2.2%
Fixed O&M	$15,955	$16,034	$79	0.5%	$16,092	$137	0.9%
Capital Cost	$5,056	$5,059	$4	0.1%	$5,075	$20	0.4%
Variable Production Cost ($/MWh)	$30.74	$30.81	$0.07	0.2%	$30.86	$0.11	0.4%
CO_2 Emissions (Million Metric Tons)	451	451	0	0.0%	449	-2	-0.4%
Hg Emissions (Tons)	1	1	0	-0.1%	1	0	-0.4%
NOx Emissions (Million Tons)	0	0	0	-5.4%	0	0	-1.5%
SO_2 Emissions (Million Tons)	0	0	0	0.2%	0	0	-1.0%
HCL Emissions (Million Tons)	0	0	0	0.1%	0	0	-0.4%
Southwest Power Pool (SPP)							
Total Capacity (GW)	60	60	0	0.0%	60	0	0.0%
Existing			0	0.0%		0	-0.1%
New Additions			0	0.0%		0	0.1%
Early Retirements			0	0.0%		0	0.1%
Electricity Prices ($/MWh)	$59.71	$59.67	-$0.04	-0.1%	$59.74	$0.02	0.0%
Generation (TWh)	216	216	0	0.0%	216	0	0.0%
Costs ($Millions)	$10,198	$10,200	$2	0.0%	$10,246	$48	0.5%
Fuel Cost	$5,633	$5,626	-$6	-0.1%	$5,634	$2	0.0%
Variable O&M	$952	$955	$3	0.3%	$967	$15	1.5%
Fixed O&M	$2,520	$2,525	$5	0.2%	$2,551	$32	1.3%
Capital Cost	$1,093	$1,094	$1	0.0%	$1,094	$1	0.1%
Variable Production Cost ($/MWh)	$30.50	$30.48	-$0.02	-0.1%	$30.57	$0.07	0.2%
CO_2 Emissions (Million Metric Tons)	121	121	0	0.0%	121	0	-0.1%
Hg Emissions (Tons)	0	0	0	0.2%	0	0	0.4%
NOx Emissions (Million Tons)	0	0	0	0.0%	0	0	-0.4%
SO_2 Emissions (Million Tons)	0	0	0	-0.3%	0	0	0.7%
HCL Emissions (Million Tons)	0	0	0	-0.1%	0	0	-5.5%
Electric Reliability Organization of Texas (TRE)							
Total Capacity (GW)	94	94	0	0.1%	94	0	0.1%
Existing			0	0.0%		0	0.0%
New Additions			0	0.1%		0	0.1%
Early Retirements			0	0.0%		0	0.0%
Electricity Prices ($/MWh)	$62.95	$62.93	-$0.01	0.0%	$63.00	$0.05	0.1%
Generation (TWh)	338	338	0	0.0%	338	0	0.0%
Costs ($Millions)	$17,250	$17,254	$4	0.0%	$17,270	$20	0.1%
Fuel Cost	$10,386	$10,367	-$19	-0.2%	$10,371	-$16	-0.1%
Variable O&M	$1,182	$1,182	$0	0.0%	$1,182	$0	0.0%
Fixed O&M	$4,021	$4,025	$5	0.1%	$4,027	$6	0.1%
Capital Cost	$1,661	$1,680	$19	1.1%	$1,691	$30	1.8%
Variable Production Cost ($/MWh)	$34.21	$34.15	-$0.06	-0.2%	$34.16	-$0.05	-0.1%
CO_2 Emissions (Million Metric Tons)	134	134	0	0.0%	134	0	0.0%
Hg Emissions (Tons)	0	0	0	0.3%	0	0	0.5%
NOx Emissions (Million Tons)	0	0	0	0.0%	0	0	0.1%
SO_2 Emissions (Million Tons)	0	0	0	0.6%	0	0	0.7%
HCL Emissions (Million Tons)	0	0	0	0.2%	0	0	0.4%

Table 5-1: Impact of Regulatory Options on National and Regional Markets at the Year 2030[a]

Economic Measures (all dollar values in $2013)	Baseline Value	Option B			Option D		
		Value	Difference	% Change	Value	Difference	% Change
Western Electricity Coordinating Council (WECC)							
Total Capacity (GW)	210	210	0	0.0%	210	0	-0.2%
Existing			0	0.0%		0	-0.2%
New Additions			0	0.0%		0	0.0%
Early Retirements			0	0.0%		0	0.2%
Electricity Prices ($/MWh)	$60.94	$60.93	-$0.01	0.0%	$60.82	-$0.12	-0.2%
Generation (TWh)	759	759	0	0.0%	759	0	0.0%
Costs ($Millions)	$31,151	$31,146	-$5	0.0%	$31,158	$7	0.0%
Fuel Cost	$15,172	$15,168	-$4	0.0%	$15,162	-$11	-0.1%
Variable O&M	$2,290	$2,289	$0	0.0%	$2,295	$6	0.2%
Fixed O&M	$9,047	$9,047	$0	0.0%	$9,060	$13	0.1%
Capital Cost	$4,642	$4,641	$0	0.0%	$4,641	-$1	0.0%
Variable Production Cost ($/MWh)	$23.02	$23.01	-$0.01	0.0%	$23.01	-$0.01	0.0%
CO_2 Emissions (Million Metric Tons)	248	248	0	0.0%	249	0	0.1%
Hg Emissions (Tons)	2	2	0	0.0%	2	0	0.2%
NOx Emissions (Million Tons)	0	0	0	-0.2%	0	0	-2.6%
SO_2 Emissions (Million Tons)	0	0	0	0.1%	0	0	0.2%
HCL Emissions (Million Tons)	0	0	0	0.0%	0	0	0.4%

a. Numbers may not add up due to rounding.
Source: U.S. EPA Analysis, 2015.

Findings for Regulatory Option B

As reported in *Table 5-1*, the Market Model Analysis indicates that Option B would have small effects on the electricity market, on both a national and regional sub-market basis, in the year 2030.

Overall at the national level, the net change in total capacity, including reductions in capacity (which includes early retirements) and capacity additions in new plants/units, is a loss of approximately 1GW in capacity (0.1 percent of total market capacity). This loss is expected to take place entirely in the SERC region (0.4 percent of total SERC capacity) and is the result of an increase in retired capacity. Consequently, Option B is expected to have minimal effect on capacity availability and supply reliability at the national level. Overall impacts on wholesale electricity prices are similarly minimal. Wholesale electricity prices are expected to increase in some NERC regions, and fall in others. Price changes in individual regions range from -$0.04 per MWh (0.1 percent) in SPP to $0.25 per MWh (0.4 percent) in MRO. Finally, at the national level, total costs increase by approximately 0.1 percent. Across regions, no NERC region records an increase in power sector total costs exceeding 0.5 percent.

At the national level, the change in emissions is small relative to baseline emissions: NOx emissions decrease by 1.5 percent and SO_2 emissions decrease by 0.1 percent; however, CO_2, Hg, and HCL emissions do not change. The impact on emissions varies across regions. Emissions increase in some and decrease in other NERC regions.[80]

[80] 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 *TDD* for details).

Findings for Regulatory Option D

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

At the national level, total annual costs increase by $752 million, or a modest 0.4 percent relative to baseline. The larger parts of this increase occur in fixed O&M. The effects of this increase on the national and regional markets are small *overall*. The net change in total capacity under Option D is essentially zero, indicating that this option would be expected to have a negligible effect on capacity availability and supply reliability, at the national level. This is the case at the regional level as well, with small capacity changes due to early retirement (MRO, SERC, SPP, and WECC) or new additions (RFC, SERC, SPP, and TRE). Option D also has a small impact on electricity prices across all NERC regions, with increases of no more than 0.5 percent and a 0.2 percent reduction in the WECC region. At the national level, variable production costs – fuel and variable O&M – increase by a small amount of $0.06 per MWh or 0.2 percent. Changes in variable costs differ across the regions and range from a $0.05 reduction in TRE (0.1 percent) to a $0.11 increase in SERC (0.4 percent).

At the national level, the change in emissions is small relative to baseline emissions: NOx emissions decrease by 0.8 percent, HCL emissions decrease by 0.5 percent, and CO_2 and SO_2 emissions decrease by 0.1 percent, while Hg emissions do not change. The impact on emissions varies across regions. Emissions increase in some and decrease in other NERC regions.[81]

Impact on Steam Electric Power Plants as a Group

For the analysis of impact on steam electric plants as a group, EPA used the same IPM V5.13 results for 2030 that were used to analyze the impact on national and regional electricity markets described above; however, this analysis considers the effect of the regulatory options on the subset of plants subject to the final ELGs, *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 final ELGs on the entire electric power sector, *i.e.*, including plants to which the final 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 (*Table 5-2*) 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 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 electric generating plants. However, in this assessment, the impact measures focus on the 672 steam electric power plants explicitly included in the industry survey and represented in IPM (as opposed to additional steam electric power plants estimated based on survey weights, which may also be represented in IPM but are not explicitly identified in the industry survey and receive no compliance costs). In addition, a few measures differ: (1) new capacity additions and prices are not relevant at the plant level, (2) changes in emissions at a subset of electric power plants, as opposed to the electricity market as a whole, 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 is presented.

[81] 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 *TDD* for details).

The following four measures are reported in the analysis of steam electric power plants as a group. In all instances, the measures are tabulated only 672 steam electric power plants explicitly included in the industry survey and analyzed in the Market Model Analysis (note that steam electric plants not included in the tabulation do not incur compliance costs for the options 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 a reduction in available capacity (see discussion above) or the less frequent dispatch of a plant due to higher production cost resulting from compliance response. At the same time, the final ELG options may lead to an increase in generation for some steam electric power plants if their compliance costs are low relative to other steam electric power plants.
- *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 5-2 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 less competitive compared to plants that do not incur compliance costs under 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. However, in the same way as described above for the market-level analysis, the impacts of Option B are generally smaller than those of Option D. Also as described above for the market-level analysis, those impacts vary across the NERC regions.

Table 5-2: Market Impact Analysis Options on Steam Electric Power Plants, as a Group, at the Year 2030[a]

Economic Measures (all dollar values in $2013)	Baseline Value	Option B			Option D		
		Value	Difference	% Change	Value	Difference	% Change
National Totals							
Total Capacity (MW)	359,982	358,909	-1,073	-0.30%	359,137	-844	-0.23%
Early Retirements – Number of Plants	80	80	0	0.00%	81	1	1.25%
Full and Partial Retirements – Capacity (MW)	93,726	94,797	1,071	1.14%	94,569	843	0.90%
Generation (GWh)	1,702,140	1,702,546	406	0.02%	1,698,961	-3,179	-0.19%
Costs ($Millions)	$82,359	$82,641	$283	0.34%	$82,855	$496	0.60%
Fuel Cost	$45,313	$45,336	$22	0.05%	$45,195	-$118	-0.26%
Variable O&M	$7,928	$8,020	$91	1.15%	$8,120	$191	2.41%
Fixed O&M	$25,385	$25,554	$168	0.66%	$25,819	$434	1.71%
Capital Cost	$3,732	$3,732	$1	0.02%	$3,721	-$11	-0.30%
Variable Production Cost ($/MWh)	$31.28	$31.34	$0.06	0.19%	$31.38	$0.10	0.33%
Florida Reliability Coordinating Council (FRCC)							
Total Capacity (MW)	24,165	24,165	0	0.00%	24,165	0	0.00%
Early Retirements – Number of Plants	5	5	0	0.00%	5	0	0.00%
Full and Partial Retirements – Capacity (MW)	7,795	7,795	0	0.00%	7,795	0	0.00%

Table 5-2: Market Impact Analysis Options on Steam Electric Power Plants, as a Group, at the Year 2030[a]

Economic Measures (all dollar values in $2013)	Baseline Value	Option B			Option D		
		Value	Difference	% Change	Value	Difference	% Change
Generation (GWh)	72,526	72,574	48	0.07%	72,565	40	0.05%
Costs ($Millions)	$4,610	$4,617	$8	0.17%	$4,623	$13	0.29%
Fuel Cost	$3,163	$3,166	$2	0.07%	$3,169	$6	0.19%
Variable O&M	$248	$249	$0	0.12%	$249	$0	0.13%
Fixed O&M	$1,174	$1,179	$5	0.46%	$1,181	$7	0.60%
Capital Cost	$24	$24	$0	-0.47%	$24	$0	-0.38%
Variable Production Cost ($/MWh)	$47.04	$47.05	$0.00	0.01%	$47.10	$0.06	0.13%
Midwest Reliability Organization (MRO)							
Total Capacity (MW)	27,725	27,762	37	0.13%	27,519	-206	-0.74%
Early Retirements – Number of Plants	10	10	0	0.00%	9	-1	-10.00%
Full and Partial Retirements – Capacity (MW)	6,874	6,838	-37	-0.53%	7,080	205	2.99%
Generation (GWh)	156,740	157,379	638	0.41%	157,337	597	0.38%
Costs ($Millions)	$6,969	$7,015	$45	0.65%	$7,056	$86	1.24%
Fuel Cost	$3,732	$3,759	$28	0.74%	$3,754	$22	0.59%
Variable O&M	$838	$843	$6	0.67%	$859	$21	2.52%
Fixed O&M	$2,012	$2,021	$8	0.40%	$2,051	$38	1.91%
Capital Cost	$388	$391	$4	1.02%	$392	$5	1.22%
Variable Production Cost ($/MWh)	$29.15	$29.25	$0.09	0.32%	$29.32	$0.16	0.56%
Northeast Power Coordinating Council (NPCC)							
Total Capacity (MW)	9,984	9,984	0	0.00%	9,984	0	0.00%
Early Retirements – Number of Plants	7	7	0	0.00%	7	0	0.00%
Full and Partial Retirements – Capacity (MW)	6,976	6,976	0	0.00%	6,976	0	0.00%
Generation (GWh)	43,922	43,965	42	0.10%	44,020	98	0.22%
Costs ($Millions)	$2,460	$2,462	$2	0.08%	$2,466	$6	0.23%
Fuel Cost	$1,506	$1,507	$1	0.07%	$1,511	$5	0.32%
Variable O&M	$94	$94	$0	0.28%	$95	$1	0.90%
Fixed O&M	$855	$855	$1	0.06%	$855	$0	0.02%
Capital Cost	$6	$6	$0	2.03%	$6	$0	-3.18%
Variable Production Cost ($/MWh)	$36.42	$36.42	$0.00	-0.01%	$36.47	$0.05	0.13%
ReliabilityFirst Corporation (RFC)							
Total Capacity (MW)	98,011	98,010	-1	0.00%	98,011	0	0.00%
Early Retirements – Number of Plants	12	12	0	0.00%	12	0	0.00%
Full and Partial Retirements – Capacity (MW)	12,090	12,090	0	0.00%	12,090	0	0.00%
Generation (GWh)	509,797	509,589	-208	-0.04%	507,979	-1,818	-0.36%
Costs ($Millions)	$25,126	$25,224	$98	0.39%	$25,328	$201	0.80%
Fuel Cost	$13,710	$13,708	-$2	-0.01%	$13,632	-$78	-0.57%
Variable O&M	$2,495	$2,518	$23	0.94%	$2,568	$73	2.93%
Fixed O&M	$7,629	$7,702	$73	0.95%	$7,840	$210	2.76%
Capital Cost	$1,292	$1,296	$4	0.31%	$1,288	-$4	-0.33%
Variable Production Cost ($/MWh)	$31.79	$31.84	$0.06	0.17%	$31.89	$0.10	0.33%

Table 5-2: Market Impact Analysis Options on Steam Electric Power Plants, as a Group, at the Year 2030[a]

Economic Measures (all dollar values in $2013)	Baseline Value	Option B			Option D		
		Value	Difference	% Change	Value	Difference	% Change
Southeast Electric Reliability Council (SERC)							
Total Capacity (MW)	101,655	100,547	-1,108	-1.09%	101,438	-217	-0.21%
Early Retirements – Number of Plants	20	20	0	0.00%	21	1	5.00%
Full and Partial Retirements – Capacity (MW)	35,025	36,133	1,108	3.16%	35,243	218	0.62%
Generation (GWh)	496,951	496,542	-410	-0.08%	494,521	-2,430	-0.49%
Costs ($Millions)	$24,066	$24,182	$116	0.48%	$24,188	$122	0.51%
Fuel Cost	$13,511	$13,502	-$9	-0.07%	$13,444	-$67	-0.50%
Variable O&M	$2,180	$2,238	$58	2.66%	$2,254	$74	3.37%
Fixed O&M	$7,315	$7,390	$74	1.02%	$7,444	$129	1.76%
Capital Cost	$1,059	$1,052	-$7	-0.64%	$1,046	-$13	-1.25%
Variable Production Cost ($/MWh)	$31.58	$31.70	$0.12	0.39%	$31.74	$0.17	0.53%
Southwest Power Pool (SPP)							
Total Capacity (MW)	25,340	25,340	0	0.00%	25,290	-50	-0.20%
Early Retirements – Number of Plants	6	6	0	0.00%	6	0	0.00%
Full and Partial Retirements – Capacity (MW)	7,997	7,997	0	0.00%	8,047	50	0.63%
Generation (GWh)	111,667	111,687	20	0.02%	111,555	-112	-0.10%
Costs ($Millions)	$5,315	$5,317	$2	0.05%	$5,352	$38	0.71%
Fuel Cost	$2,825	$2,822	-$3	-0.11%	$2,822	-$3	-0.11%
Variable O&M	$646	$648	$2	0.37%	$660	$14	2.13%
Fixed O&M	$1,519	$1,524	$4	0.28%	$1,548	$29	1.90%
Capital Cost	$325	$323	-$1	-0.35%	$323	-$2	-0.52%
Variable Production Cost ($/MWh)	$31.08	$31.07	-$0.01	-0.04%	$31.21	$0.13	0.41%
Texas Regional Entity (TRE)							
Total Capacity (MW)	26,709	26,709	0	0.00%	26,708	-1	-0.01%
Early Retirements – Number of Plants	4	4	0	0.00%	4	0	0.00%
Full and Partial Retirements – Capacity (MW)	5,949	5,949	0	0.00%	5,949	0	0.00%
Generation (GWh)	89,074	89,194	120	0.13%	89,267	193	0.22%
Costs ($Millions)	$3,999	$4,003	$4	0.11%	$4,007	$9	0.21%
Fuel Cost	$2,019	$2,020	$1	0.06%	$2,022	$3	0.17%
Variable O&M	$386	$387	$1	0.29%	$388	$2	0.41%
Fixed O&M	$1,460	$1,462	$2	0.11%	$1,462	$2	0.11%
Capital Cost	$134	$134	$1	0.45%	$136	$2	1.49%
Variable Production Cost ($/MWh)	$27.00	$26.99	-$0.01	-0.04%	$27.00	$0.00	-0.01%
Western Electricity Coordinating Council (WECC)							
Total Capacity (MW)	46,392	46,392	0	0.00%	46,022	-370	-0.80%
Early Retirements – Number of Plants	16	16	0	0.00%	17	1	6.25%
Full and Partial Retirements – Capacity (MW)	11,020	11,020	0	0.00%	11,390	370	3.36%
Generation (GWh)	221,462	221,617	155	0.07%	221,715	253	0.11%
Costs ($Millions)	$9,814	$9,820	$6	0.06%	$9,835	$21	0.22%

Table 5-2: Market Impact Analysis Options on Steam Electric Power Plants, as a Group, at the Year 2030[a]

Economic Measures (all dollar values in $2013)	Baseline Value	Option B			Option D		
		Value	Difference	% Change	Value	Difference	% Change
Fuel Cost	$4,848	$4,852	$4	0.09%	$4,842	-$6	-0.11%
Variable O&M	$1,041	$1,041	$0	0.03%	$1,048	$7	0.65%
Fixed O&M	$3,420	$3,421	$1	0.04%	$3,438	$18	0.54%
Capital Cost	$506	$506	$0	0.00%	$507	$2	0.32%
Variable Production Cost ($/MWh)	$26.59	$26.59	$0.00	0.01%	$26.56	-$0.02	-0.09%

a. Numbers may not add up due to rounding.
Source: U.S. EPA Analysis, 2015.

Findings for Regulatory Option B

Under Option B, as is the case for the electricity market as a whole, the net change in total capacity for the group of steam electric power plants is small.

For the group of steam electric power plants, total capacity decreases by 1,073 MW or approximately 0.30 percent of the 359,982 MW in baseline capacity. This results from capacity closures of 1,108 MW in the SERC region and *avoided* capacity closures of 37 MW in the MRO region. Option B results in no full (plant) closures in any of the NERC regions.

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,[82] for steam electric power plants, total available capacity and electricity generation at the national level is projected to increase by less than 0.1 percent. At the regional level, two NERC regions – RFC and SERC – are projected to experience a very small decline in electricity generation from steam electric power plants, ranging from 208 GWh in RFC (0.04 percent) to 410 GWh in SERC (0.08 percent). Two NERC regions are projected to experience increases in generation greater than 0.1 percent: MRO (638 GWh, or 0.41 percent) and TRE (120 GWh, or 0.13 percent). The other four NERC regions each are projected to experience a small increase in electricity generation from steam electric power plants of less than or equal to 0.1 percent.

At the national level, variable production costs at steam electric power plants increase by approximately 0.2 percent. These effects vary by region from -0.04 percent in SPP and TRE, to 0.4 percent in SERC. These findings of very small effects confirm EPA's assessment that Option B can be expected to have little economic consequence in national and regional electricity markets.

Findings for Regulatory Option D

Results of the analysis for Option D show small reductions in steam electric generating capacity and electricity generation of 844 MW (0.2 percent) and 3,179 GWh (0.2 percent), respectively. The steam electric capacity reduction includes early retirements and avoided retirement of plants and generating units with the net effect of the two types of changes being small capacity losses. Under the Option D analysis, one plant is expected to close (in the SERC region) and two plants are expected to avoid closure (in the MRO and WECC regions), leading to an estimated net closure of one plant. Including these plant closures, the analysis for this

[82] 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.

option projects total full and partial capacity closures of 843 MW. This change is based on a mixture of incremental capacity closures (1,416 MW nationally, corresponding to roughly 8 generating units) and *avoided* capacity closures (574 MW nationally, corresponding to 6 generating units). *Table 5-3* details the changes in capacity closures corresponding to the net change of 843 MW (corresponding to 2 generating units).

Table 5-3: Incremental and Avoided Capacity Closures by NERC Region for Regulatory Option D

NERC Region	Incremental Capacity Closure (MW)	Avoided Capacity Closure (MW)	Net Capacity Closure (MW)
MRO	294	89	205
SERC	703	485	218
SPP	50	0	50
WECC	370	0	370
Total	**1,416**	**574**	**843**

a. Numbers may not add up due to rounding.
Source: U.S. EPA Analysis, 2015.

Findings for the change in total costs and variable production costs under this Option exceed those under Option B but remain modest. The model projects a 0.6 percent increase in total costs at the national level in 2030, with the MRO region recording the largest increase of 1.2 percent. At the national level, the increase in total costs occurs in fixed and variable O&M (1.7 percent and 2.4 percent, respectively) while fuel costs and capital costs decline (each by approximately 0.3 percent). Variable production costs increase by 0.3 percent, with the MRO region recording the highest increase of 0.6 percent.

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, EPA analyzed the distribution of plant-specific changes between the baseline and the post-compliance cases for the following three metrics:

- *Capacity Utilization*, defined as generation divided by capacity times 8,760 hours
- *Electricity Generation*, as defined above
- *Variable Production Costs per MWh*, defined as variable O&M cost plus fuel cost divided by net generation

Table 5-4 presents the estimated number of steam electric power plants with specific degrees of change in operations and financial performance as a result of regulatory options. Metrics of interest include the number of plants with reductions in capacity utilization or generation (on left side of the table), and the number of plants with increases in variable production costs (on 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.*, under the analyzed Option, a plant is assessed as either a full, partial, or avoided closure in either the baseline or the post-compliance case. As a result, the measures presented in *Table 5-2*, 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 post-compliance case, the percent change in electricity generation relative to baseline cannot be calculated. On this basis, 246 and 247 plants are excluded from assessment of effects on individual steam electric power plants under Options B and D, respectively.

In addition, the change in variable production cost per MWh of generation could not be developed for 40 plants with zero generation in either baseline or post-compliance cases under Options B and D. For these plants, variable production cost per MWh cannot be calculated for one or other of the two cases (because the divisor, MWh, is zero), and therefore the change in variable production cost per MWh cannot be meaningfully determined. For *change in variable production cost per MWh*, these plants are recorded in the "N/A" column.

Table 5-4: Impact of Market Impact Analysis Options on Individual Steam Electric Power Plants at the Year 2030 (number of steam electric power plants with indicated effect)

Economic Measures	Reduction			No Change	Increase			N/A[b,c]
	≥ 3%	≥1% and <3%	<1%		<1%	≥1% and <3%	≥ 3%	
Option B								
Change in Capacity Utilization[a]	5	6	125	118	137	5	6	246
Change in Generation	10	4	124	114	125	12	13	246
Change in Variable Production Costs/MWh	1	1	162	0	187	9	2	286
Option D								
Change in Capacity Utilization[a]	10	7	54	226	79	13	12	247
Change in Generation	14	7	24	290	30	10	26	247
Change in Variable Production Costs/MWh	1	0	58	15	244	36	7	287

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

b. Plants with operating status changes in either baseline or post-compliance scenario have been excluded from general table calculations. Thus, for Option B, "N/A" reports 124 full and 118 partial baseline plant closures;1 full and 2 partial policy closures; and 1 avoided partial closure . For Option D, "N/A" reports 124 full and 115 partial baseline plant closures; 3 full and 4 partial policy closures; and 1 avoided partial closure.

c. The change in variable production cost per MWh could not be developed for 40 plants with zero generation in either the baseline case or Options B or D post-compliance cases.

Source: U.S. EPA Analysis, 2015.

Findings for Regulatory Option B

For Option B, the analysis of changes in individual plants indicates that most plants experience only slight effects – *i.e.*, no change or less than a 1 percent reduction or 1 percent increase. Only 11 plants (2 percent) are estimated to incur a reduction in capacity utilization of at least 1 percent and 14 plants (2 percent) incur a reduction in generation of at least 1 percent.[83] Finally, only 11 plants (2 percent) are estimated incur an increase in variable production costs of at least 1 percent.

Findings for Regulatory Option D

Under Option D, the analysis indicates that most plants experience only slight effects, though these effects are greater than for Option B. Option D shows small reductions in capacity utilization and generation; only 17 and 21 plants (approximately 3 percent) incur more than a 1 percent reduction in capacity utilization and generation, respectively. Impacts on variable costs are larger than for Option B, but still modest. The increase in variable production costs is estimated to exceed 1 percent for 43 plants (6 percent), 36 of which have an

[83] There are 7 and 6 plants with reductions in capacity utilization 1-3 percent and at least 3 percent, respectively; and 3 and 15 plants with reductions in generation 1-3 percent and at least 3 percent, respectively.

increase of at least 1 percent but less than 3 percent. The vast majority of steam electric power plants have variable production costs that increase by less than 1 percent (or decline).

5.3.2 Analysis Results for 2020 – To Capture the Short-Term Effect of Compliance with Final ELGs

This section presents market-level results for the final ELG options for the 2020 model run year, which represents the years 2019 through 2022. As discussed above, this run year captures the majority of the period when steam electric power plants would be implementing compliance technologies. Higher electricity production costs at steam electric power plants due to compliance with the final ELGs may lead to higher electricity production costs at the level of the electric power sector. Because these effects are of most concern in terms of potential impact on national and regional electricity markets, this section presents results only for the total set of plants analyzed in IPM and does not present results for the subset of only steam electric power plants.

Table 5-5 presents the following national and NERC-region market-level impacts for 2020:

- Electricity price changes, including changes in energy prices and capacity prices
- Generation changes
- Cost changes, including changes in fuel costs, variable O&M costs, fixed O&M costs, and capital costs
- Changes in variable production costs per MWh
- Changes in CO_2, Hg, NOx, SO_2 and HCL emissions.

Table 5-5 presents the results for the baseline and policy cases, the absolute difference between the two cases, and the percentage difference. The following discussion of the impact findings for the two regulatory options focuses on these differences.

Table 5-5: Short-Term Effect of Compliance with Regulatory Options on National Electricity Market - 2020[a]

Economic Measures (all dollar values in $2013)	Baseline Value	Option B			Option D		
		Value	Difference	% Change	Value	Difference	% Change
National Totals							
Electricity Prices ($/MWh)	NA	NA	NA	NA	NA	NA	NA
Generation (TWh)	4,100	4,099	-1	0.0%	4,099	-1	-0.0%
Costs ($Millions)	$182,039	$182,427	$389	0.2%	$182,918	$879	0.5%
Fuel Cost	$98,308	$98,418	$110	0.1%	$98,560	$253	0.3%
Variable O&M	$13,800	$13,870	$70	0.5%	$13,960	$160	1.2%
Fixed O&M	$52,905	$53,037	$132	0.2%	$53,237	$332	0.6%
Capital Cost	$17,027	$17,103	$76	0.4%	$17,161	$134	0.8%
Variable Production Cost ($/MWh)	$27.35	$27.39	$0.05	0.2%	$27.45	$0.10	0.4%
CO_2 Emissions (Million Metric Tonnes)	1,755	1,753	-2	-0.1%	1,750	-5	-0.3%
Mercury Emissions (Tons)	7	7	0	-0.2%	7	0	-0.5%
NOx Emissions (Million Tons)	1	1	0	-1.6%	1	0	-1.2%
SO_2 Emissions (Million Tons)	1	1	0	-0.4%	1	0	-0.5%
HCL Emissions (Million Tons)	0	0	0	-0.1%	0	0	-0.1%

Table 5-5: Short-Term Effect of Compliance with Regulatory Options on National Electricity Market - 2020[a]

Economic Measures (all dollar values in $2013)	Baseline Value	Option B			Option D		
		Value	Difference	% Change	Value	Difference	% Change
Florida Reliability Coordinating Council (FRCC)							
Electricity Prices ($/MWh)	$61.16	$61.22	$0.06	0.1%	$61.30	$0.14	0.2%
Generation (TWh)	236	236	0	0.0%	236	0	0.0%
Costs ($Millions)	$13,879	$13,898	$19	0.1%	$13,916	$37	0.3%
Fuel Cost	$9,692	$9,706	$15	0.2%	$9,723	$32	0.3%
Variable O&M	$752	$752	$0	0.0%	$752	$0	0.0%
Fixed O&M	$2,175	$2,179	$4	0.2%	$2,180	$6	0.3%
Capital Cost	$1,260	$1,260	$0	0.0%	$1,260	$0	0.0%
Variable Production Cost ($/MWh)	$44.29	$44.35	$0.06	0.1%	$44.43	$0.13	0.3%
CO_2 Emissions (Million Metric Tonnes)	77	77	0	0.0%	77	0	0.0%
Mercury Emissions (Tons)	0	0	0	0.0%	0	0	0.0%
NOx Emissions (Million Tons)	0	0	0	-0.7%	0	0	0.0%
SO_2 Emissions (Million Tons)	0	0	0	0.3%	0	0	0.3%
HCL Emissions (Million Tons)	0	0	0	-0.1%	0	0	-0.1%
Midwest Reliability Organization (MRO)							
Electricity Prices ($/MWh)	$52.69	$52.90	$0.21	0.4%	$53.45	$0.76	1.4%
Generation (TWh)	255	256	1	0.2%	256	1	0.4%
Costs ($Millions)	$10,366	$10,409	$42	0.4%	$10,471	$105	1.0%
Fuel Cost	$4,436	$4,459	$23	0.5%	$4,477	$42	0.9%
Variable O&M	$1,035	$1,040	$5	0.5%	$1,054	$18	1.7%
Fixed O&M	$3,601	$3,609	$8	0.2%	$3,634	$33	0.9%
Capital Cost	$1,294	$1,301	$7	0.5%	$1,306	$12	1.0%
Variable Production Cost ($/MWh)	$21.46	$21.52	$0.06	0.3%	$21.62	$0.15	0.7%
CO_2 Emissions (Million Metric Tonnes)	141	141	0	0.3%	141	1	0.4%
Mercury Emissions (Tons)	1	1	0	0.1%	1	0	0.1%
NOx Emissions (Million Tons)	0	0	0	-0.4%	0	0	0.4%
SO_2 Emissions (Million Tons)	0	0	0	0.4%	0	0	0.5%
HCL Emissions (Million Tons)	0	0	0	0.1%	0	0	0.1%
Northeast Power Coordinating Council (NPCC)							
Electricity Prices ($/MWh)	$62.82	$62.85	$0.03	0.0%	$63.14	$0.33	0.5%
Generation (TWh)	241	241	0	0.0%	241	0	0.0%
Costs ($Millions)	$11,240	$11,249	$10	0.1%	$11,259	$20	0.2%
Fuel Cost	$5,993	$5,995	$1	0.0%	$6,006	$12	0.2%
Variable O&M	$498	$498	$0	0.0%	$497	$0	-0.1%
Fixed O&M	$3,819	$3,819	$0	0.0%	$3,822	$3	0.1%
Capital Cost	$929	$938	$9	0.9%	$935	$6	0.6%
Variable Production Cost ($/MWh)	$26.91	$26.92	$0.01	0.0%	$26.97	$0.06	0.2%
CO_2 Emissions (Million Metric Tonnes)	50	50	0	0.0%	50	0	-0.1%
Mercury Emissions (Tons)	0	0	0	0.1%	0	0	0.0%
NOx Emissions (Million Tons)	0	0	0	-2.9%	0	0	0.1%
SO_2 Emissions (Million Tons)	0	0	0	0.4%	0	0	0.4%
HCL Emissions (Million Tons)	0	0	0	0.2%	0	0	0.2%

Table 5-5: Short-Term Effect of Compliance with Regulatory Options on National Electricity Market - 2020[a]

Economic Measures (all dollar values in $2013)	Baseline Value	Option B			Option D		
		Value	Difference	% Change	Value	Difference	% Change
ReliabilityFirst Corporation (RFC)							
Electricity Prices ($/MWh)	$54.95	$55.08	$0.13	0.2%	$55.62	$0.66	1.2%
Generation (TWh)	964	964	0	0.0%	964	0	0.0%
Costs ($Millions)	$44,805	$44,923	$118	0.3%	$45,145	$339	0.8%
Fuel Cost	$21,372	$21,389	$17	0.1%	$21,452	$80	0.4%
Variable O&M	$3,491	$3,514	$23	0.7%	$3,562	$71	2.0%
Fixed O&M	$15,132	$15,186	$54	0.4%	$15,278	$145	1.0%
Capital Cost	$4,810	$4,833	$24	0.5%	$4,853	$43	0.9%
Variable Production Cost ($/MWh)	$25.79	$25.83	$0.04	0.2%	$25.94	$0.15	0.6%
CO_2 Emissions (Million Metric Tonnes)	511	511	-1	-0.1%	509	-2	-0.5%
Mercury Emissions (Tons)	2	2	0	-0.4%	2	0	-1.2%
NOx Emissions (Million Tons)	0	0	0	-0.4%	0	0	-1.2%
SO_2 Emissions (Million Tons)	0	0	0	-0.3%	0	0	-0.6%
HCL Emissions (Million Tons)	0	0	0	0.2%	0	0	0.2%
Southeast Electric Reliability Council (SERC)							
Electricity Prices ($/MWh)	$55.36	$55.53	$0.17	0.3%	$55.84	$0.48	0.9%
Generation (TWh)	1,095	1,095	-1	0.0%	1,094	-1	-0.1%
Costs ($Millions)	$49,520	$49,669	$149	0.3%	$49,736	$216	0.4%
Fuel Cost	$27,547	$27,577	$30	0.1%	$27,586	$39	0.1%
Variable O&M	$3,604	$3,644	$41	1.1%	$3,662	$58	1.6%
Fixed O&M	$14,599	$14,657	$58	0.4%	$14,701	$102	0.7%
Capital Cost	$3,771	$3,791	$20	0.5%	$3,788	$17	0.4%
Variable Production Cost ($/MWh)	$28.44	$28.52	$0.08	0.3%	$28.56	$0.13	0.4%
CO_2 Emissions (Million Metric Tonnes)	460	459	-2	-0.4%	457	-3	-0.7%
Mercury Emissions (Tons)	1	1	0	-0.7%	1	0	-1.1%
NOx Emissions (Million Tons)	0	0	0	-6.1%	0	0	-2.2%
SO_2 Emissions (Million Tons)	0	0	0	-0.9%	0	0	-2.0%
HCL Emissions (Million Tons)	0	0	0	-0.4%	0	0	-0.8%
Southwest Power Pool (SPP)							
Electricity Prices ($/MWh)	$54.65	$54.76	$0.11	0.2%	$55.04	$0.39	0.7%
Generation (TWh)	223	223	0	0.0%	223	0	0.1%
Costs ($Millions)	$9,711	$9,718	$7	0.1%	$9,772	$61	0.6%
Fuel Cost	$5,462	$5,466	$5	0.1%	$5,482	$21	0.4%
Variable O&M	$982	$983	$2	0.2%	$990	$8	0.9%
Fixed O&M	$2,217	$2,221	$4	0.2%	$2,241	$24	1.1%
Capital Cost	$1,051	$1,047	-$3	-0.3%	$1,058	$8	0.7%
Variable Production Cost ($/MWh)	$28.89	$28.93	$0.03	0.1%	$28.99	$0.09	0.3%
CO_2 Emissions (Million Metric Tonnes)	126	126	0	0.0%	126	0	0.0%
Mercury Emissions (Tons)	0	0	0	0.0%	0	0	0.2%
NOx Emissions (Million Tons)	0	0	0	-0.2%	0	0	-0.5%
SO_2 Emissions (Million Tons)	0	0	0	-0.3%	0	0	5.7%
HCL Emissions (Million Tons)	0	0	0	-0.1%	0	0	1.3%

Table 5-5: Short-Term Effect of Compliance with Regulatory Options on National Electricity Market - 2020[a]

Economic Measures (all dollar values in $2013)	Baseline Value	Option B Value	Option B Difference	Option B % Change	Option D Value	Option D Difference	Option D % Change
Texas Regional Entity (TRE)							
Electricity Prices ($/MWh)	$57.39	$57.60	$0.21	0.4%	$57.73	$0.34	0.6%
Generation (TWh)	343	343	0	0.0%	343	0	0.0%
Costs ($Millions)	$16,144	$16,170	$25	0.2%	$16,202	$58	0.4%
Fuel Cost	$9,780	$9,780	$0	0.0%	$9,780	$1	0.0%
Variable O&M	$1,187	$1,188	$0	0.0%	$1,188	$1	0.1%
Fixed O&M	$3,652	$3,657	$5	0.1%	$3,661	$9	0.2%
Capital Cost	$1,525	$1,546	$21	1.4%	$1,573	$48	3.1%
Variable Production Cost ($/MWh)	$32.02	$32.02	$0.00	0.0%	$32.02	$0.00	0.0%
CO_2 Emissions (Million Metric Tonnes)	141	141	0	0.0%	141	0	-0.2%
Mercury Emissions (Tons)	0	0	0	0.2%	0	0	0.3%
NOx Emissions (Million Tons)	0	0	0	-0.1%	0	0	-0.2%
SO_2 Emissions (Million Tons)	0	0	0	-0.8%	0	0	0.3%
HCL Emissions (Million Tons)	0	0	0	0.2%	0	0	0.2%
Western Electricity Coordinating Council (WECC)							
Electricity Prices ($/MWh)	$54.87	$54.96	$0.08	0.2%	$54.88	$0.01	0.0%
Generation (TWh)	743	742	-1	-0.1%	742	-1	-0.1%
Costs ($Millions)	$26,374	$26,392	$18	0.1%	$26,417	$43	0.2%
Fuel Cost	$14,027	$14,045	$19	0.1%	$14,054	$27	0.2%
Variable O&M	$2,251	$2,251	$0	0.0%	$2,255	$4	0.2%
Fixed O&M	$7,710	$7,710	$0	0.0%	$7,721	$11	0.1%
Capital Cost	$2,387	$2,387	$0	0.0%	$2,388	$1	0.0%
Variable Production Cost ($/MWh)	$21.92	$21.96	$0.04	0.2%	$21.98	$0.06	0.3%
CO_2 Emissions (Million Metric Tonnes)	248	248	0	0.0%	248	0	0.1%
Mercury Emissions (Tons)	2	2	0	0.0%	2	0	0.2%
NOx Emissions (Million Tons)	0	0	0	-0.2%	0	0	-2.6%
SO_2 Emissions (Million Tons)	0	0	0	0.0%	0	0	0.0%
HCL Emissions (Million Tons)	0	0	0	0.0%	0	0	0.0%

a. Numbers may not add up due to rounding.
Source: U.S. EPA Analysis, 2015.

Findings for Regulatory Option B

As discussed earlier, steam electric power plants are expected to implement control technologies during the 5-year period of 2019 through 2023, the first four years of which fall in the range of years represented by the 2020 IPM run year (for details see *Appendix E*). Consequently, results for the year 2020 are indicative of annual effects during most of the implementation period.

As shown in *Table 5-5*, the estimated effects of compliance-technology implementation under Option B are small. At the national level, total production costs increase by 0.2 percent; this increase is driven by higher variable and fixed O&M costs (0.5 percent and 0.2 percent increases, respectively). Capital and fuel costs increase by 0.4 percent and 0.1 percent, respectively. Total production costs increase in all NERC regions, with MRO recording the largest increase of 0.4 percent. At the regional level, the impact on production-cost components varies across NERC regions and by cost component; generally, all cost components increase by a relatively small proportion. Exceptions include decreased capital costs (0.3 percent) projected in the SPP region, and two cost component increases greater than one percent in the TRE (capital costs increase by 1.4 percent) and SERC regions (variable O&M increases by 1.1 percent).

At the national level, variable production costs ($/MWh) increase by approximately 0.2 percent. While the effect on energy production costs varies at the regional level, this effect is small overall. Of the eight NERC regions modeled by IPM, variable production costs increase by no more than $0.08 per MWh or 0.3 percent, with the maximum increase occurring in SERC, and the minimum (<$0.01 per MWh) occurring in TRE.

Another potential market level impact of the final ELGs is the possible increase in electricity prices. While electricity prices increase in all NERC regions, the magnitude of that increase is small, ranging from $0.03 per MWh (less than 0.1 percent) in NPCC to $0.21 per MWh (0.4 percent) in MRO and TRE.

Finally, the impact on emissions is also small. At the national level, all emissions decline, including CO_2 (0.1 percent), Hg (0.2 percent), NOx (1.6 percent), SO_2 (0.4 percent), and HCl (0.1 percent) emissions. While the impact on emissions varies by NERC region, increasing in some and declining in others, overall changes are small relative to the baseline.[84]

Findings for Regulatory Option D

Overall, although national and regional market impacts of Option D in 2020 are greater compared to those of Option B, they remain small.

At the national level, total production costs increase by 0.5 percent; this increase is mainly driven by increases in variable O&M costs (1.2 percent), although all other cost categories increase, including capital costs (0.8 percent), fixed O&M costs (0.6 percent), and fuel costs (0.3 percent). The impact of Option D on production-cost components varies across NERC regions and by cost component, with all cost components increasing in nearly all regions, except a decline in variable O&M costs in the NPCC region (0.1 percent).

At the national level, variable production costs increase by 0.4 percent. Here also, the effect on energy production costs varies by region but is generally small, ranging from a 0.4 percent increase in WECC to a 1.4 percent increase in RFC. The effect on electricity prices reflects changes in variable production costs which vary across NERC regions, ranging from less than $0.01 per MWh (less than 0.1 percent) in TRE to $0.15 per MWh (0.7 percent) in MRO.

The effects of Option D on air emissions are also small. At the national level, CO_2, Hg, NOx, SO_2, and HCl emissions decline by 0.3 percent, 0.5 percent, 1.2 percent, 0.5 percent, and 0.1 percent, respectively. Emissions changes vary across NERC regions, increasing in some and declining in others, but are generally small.

5.4 Estimated Effects of the ELGs on New Capacity

As noted previously, the IPM baseline analysis projects no new coal-fired capacity that would be expected to incur cost due to NSPS requirements, and this continues to be the case under the policy cases. The IPM analysis therefore provides limited insight to determine whether the additional costs, by themselves, would affect investment decisions in new coal-fired plants and therefore pose a barrier to entry.

[84] 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 *TDD* for details).

5.5 Uncertainties and Limitations

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

- *Demand for electricity*: IPM assumes that electricity demand at the national level will not change between the baseline and the analyzed post-compliance options (generation within the regions is allowed to vary); this constraint is exogenous to the model. IPM v5.13 embeds a baseline energy demand forecast that is derived from the Department of Energy's *Annual Energy Outlook 2013* (AEO2013). IPM does not capture changes in demand that may result from electricity price increases associated with the final ELGs (*i.e.*, demand is inelastic with respect to price). While this constraint may overestimate total demand in policy options that have higher compliance cost and, therefore, potentially more substantial price increases, EPA believes that it does not affect the results analyzed in support of the final ELGs. As described in *Section 5.3.1* and *Section 5.3.2*, the price increases associated with the analyzed regulatory options in most NERC regions are small. EPA therefore concludes that the assumption of inelastic demand-responses to 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 AEO2013'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 expected to affect the cost of electricity generation and therefore the amount of electricity generated by steam electric power plants, irrespective of the final ELGs. 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 analyzed policy options. Holding international imports fixed potentially overstates production costs and electricity prices in U.S. domestic markets, because imports are not subject to the rule and may therefore become more competitive relative to domestic capacity, displacing some of the more expensive domestic generating units. On the other hand, holding imports fixed may understate effects on marginal domestic units, which may be displaced by increased imports. 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 (less than 0.1 percent).
- *Clean Power Plan*: The final Clean Power Plan provides states considerable flexibility in developing state implementation plans to meet the rate or mass targets. This flexibility provides states great leeway to meet key priorities. However, it induces a considerable degree of uncertainty in what the future electric power market will look like and the overall economic impacts of the final ELGs. For example, states may choose to comply with the Clean Power Plan in ways that will lead to fewer or more coal-fired steam ELG plant retirements than the IPM runs would indicate. Such differences may have an important impact on dispatch profiles, new capacity, production costs, prices, and emission changes.

6 Assessment of the Impact of the Final ELGs on Employment

6.1 Background and Context

In addition to addressing the costs and benefits of the final rule, EPA has analyzed the impacts of this rulemaking on employment. These impacts are presented in this section. While a standalone analysis of employment impacts is not included in a standard cost-benefit analysis, such an analysis is of particular concern in the current economic climate given continued interest in the employment impact of regulations such as this final rule. Executive Order 13563, states, "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.

This analysis of potential employment effects uses detailed engineering information on labor requirements for each of the control technologies analyzed for the final ELGs in order to estimate partial employment impacts for affected entities in the power sector as well as several related industries. These bottom-up, engineering-based estimates represent only one portion of potential employment impacts within the regulated and closely related industries, and do not represent estimates of the net employment impacts of this rule.

In this Chapter, EPA first provides an overview of the various ways that environmental regulation can affect employment. EPA then qualitatively describes potential employment impacts for: coal-fired steam electric power plants, pollution control suppliers, and virgin material suppliers. The chapter concludes with partial employment impact estimates at coal-fired steam electric power plants based on (1) the estimated labor required to operate and maintain the compliance equipment that is expected to be installed at these plants to meet the final ELGs, and (2) estimated decreases in the quantity of electricity generated by these plants and associated employment effects. In addition, EPA estimates labor effects for coal mining, natural gas extraction, natural gas-fired generating plants, and the sectors involved in constructing new gas power plants.

6.1.1 Employment Impacts of Environmental Regulations

From an economic perspective, labor is an input into producing goods and services; if a regulation requires that more labor be used to produce a given amount of output, that additional labor is reflected in an increase in the cost of production. Moreover, when the economy is at full employment, we would not expect an environmental regulation to have an impact on overall employment because labor is being shifted from one sector to another. On the other hand, in periods of high unemployment, employment effects (both positive and negative) are possible.

For example, an increase in labor demand due to regulation may result in a short-term net increase in overall employment as workers are hired by the regulated sector to help meet new requirements (*e.g.*, to install new equipment) or by the environmental protection sector to produce new abatement capital resulting in hiring previously unemployed workers. When significant numbers of workers are unemployed, the opportunity costs associated with displacing jobs in other sectors are likely to be higher. And, in general, if a regulation imposes high costs and does not increase the demand for labor, it may lead to a decrease in employment. The responsiveness of industry labor demand depends on how these forces interact. Economic theory indicates that the responsiveness of industry labor demand depends on a number of factors: price elasticity of demand for the product, substitutability of other factors of production, elasticity of supply of other factors of production, and labor's share of total production costs. Berman and Bui (2001) put this theory in the context of environmental regulation, and suggest that, for example, if all firms in the industry are faced with the same compliance costs of regulation and product demand is inelastic, then industry output may not change much at all.

Regulations set in motion new orders for pollution control equipment and services. New categories of employment have been created in the process of implementing environmental regulations. When a regulation is promulgated, one typical response of industry is to order pollution control equipment and services in order to comply with the regulation when it becomes effective. Conversely, the closure of plants that choose not to comply – and any changes in production levels at plants choosing to comply and remain in operation – occur after the compliance date, or earlier in anticipation of the compliance obligation. Environmental regulation may increase revenue and employment in the environmental technology industry. While these increases represent gains for that industry, they translate into costs to the regulated industries required to install the equipment.

Environmental regulations support employment in many basic industries. Regulated firms either hire workers to design and build pollution controls directly or purchase pollution control devices from a third party for installation. Once the equipment is installed, regulated firms hire workers to operate and maintain the pollution control equipment—much like they hire workers to produce more output. In addition to the increase in employment in the environmental protection industry (via increased orders for pollution control equipment), environmental regulations also support employment in industries that provide intermediate goods to the environmental protection industry. The equipment manufacturers, in turn, order steel, tanks, vessels, blowers, pumps, and chemicals to manufacture and install the equipment. Currently in most cases there is no scientifically defensible way to generate sufficiently reliable estimates of the employment impacts in these intermediate goods sectors.

It is sometimes claimed that new or more stringent environmental regulations raise production costs thereby reducing production, which in turn must lead to lower employment. However, the peer-reviewed literature indicates that determining the direction of net employment effects in a regulated industry is challenging due to competing effects. Environmental regulations are assumed to raise production costs and thereby the cost of output, so we expect the "output" effect of environmental regulation to be negative (higher prices lead to lower sales). On the other hand, complying with the new or more stringent regulation requires additional inputs, including labor, and may alter the relative proportions of labor and capital used by regulated firms in their production processes. Berman and Bui (2001) demonstrate using standard neoclassical microeconomics that environmental regulations have an ambiguous effect on employment in the regulated sector.[85, 86] Berman and Bui's theoretical results imply that the effect of environmental regulation on employment in the regulated sector is an empirical question.

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 would primarily be reallocated from one productive use to another (*e.g.*, from producing electricity or steel to producing pollution abatement equipment). Theory supports the argument that, in the case of full employment, the net national employment effects from environmental regulation are likely to be small and transitory (*e.g.*, as workers move from one job to another). On the other hand, if the economy is operating at less than full employment, economic theory

85 Berman, E. and L. T. M. Bui (2001). "Environmental Regulation and Labor Demand: Evidence from the South Coast Air Basin." Journal of Public Economics 79(2): 265-295.

86 Morgenstern, Pizer, and Shih (2002) develop a similar model. Morgenstern, R. D., W. A. Pizer, and J. S. Shih. 2002. Jobs versus the Environment: An Industry-Level Perspective.‖ Journal of Environmental Economics and Management 43(3):412-436.

does not clearly indicate the direction or magnitude of the net impact of environmental regulation on employment; it could cause either a short-run net increase or short-run net decrease (Schmalansee and Stavins, 2011). An important fundamental research question is how to accommodate unemployment as a structural feature in economic models. This feature may be important in evaluating the impact of large-scale regulation on employment (Smith, 2012).

Affected sectors may experience transitory effects as workers change jobs. Some workers may need to retrain or relocate in anticipation of the new requirements or require time to search for new jobs, while shortages in some sectors or regions could bid up wages to attract workers. It is important to recognize that these adjustment costs can entail local labor disruptions, and although the net change in the national workforce is expected to be small, localized reductions in employment can still have negative impacts on individuals and communities just as localized increases can have positive impacts.

To summarize the discussion in this section, economic theory provides a framework for analyzing the impacts of environmental regulation on employment. The net employment effect incorporates expected employment changes (both positive and negative) in the regulated sector, the environmental protection sector, and other relevant sectors. Using economic theory, labor demand impacts for regulated firms, and also for the regulated industry, can be decomposed into output and substitution effects. With these potentially competing forces, under standard neoclassical theory estimation of net employment effects is possible with empirical study specific to the regulated firms and firms in the environmental protection sector and other relevant sectors when data and methods of sufficient detail and quality are available.

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 only a few papers that examine the impact of environmental regulation on employment, but this area of the literature has been growing. As stated previously in this RIA section, empirical results from 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 more highly regulated counties may generate fewer jobs than less regulated ones (Greenstone 2002, Walker 2011). 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 a 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 work loss days and sick days as well as mortality are reduced when air pollution is reduced. EPA's study of the benefits and costs of implementing the clean air regulations used these studies to predict how increased labor availability would increase the labor supply and improve productivity and the economy. Another literature estimates how worker productivity improves at the work site when pollution is reduced. 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 from 2009 and 2010, paired with local ozone air quality monitoring data for one large California farm growing multiple crops, with a piece-rate payment structure. Their quasi-experimental structure identifies an effect of daily variation in monitored ozone levels on productivity. They find "that ozone levels well below federal air quality standards have a significant impact on productivity: a 10 parts per billion (ppb) decrease in ozone concentrations increases worker productivity by 5.5 percent." (Graff Zivin and Neidell, 2012, p. 3654). Such studies are a compelling start to exploring this new area of research, considering the benefits of improved air 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 very 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. Quantitative estimates are further complicated by the fact that macroeconomic models often have very little sectoral detail and usually assume that the economy is at full employment. The EPA is currently in the process of seeking input from an independent expert panel on modeling economy-wide impacts, including employment effects.[87]

6.2 Analysis Overview

The final ELG rule may affect employment in at least seven sectors or sub-sectors:

1. Coal-fired steam electric power plants;
2. Suppliers of pollution control equipment used by coal-fired steam electric power plants to meet the ELGs;
3. Suppliers of virgin materials that may be replaced by materials generated by steam electric plants as by-products of complying with the ELGs;
4. Coal mining;
5. Natural gas-fueled electric power plants that may increase generation in response to changes in coal-fired generation;
6. Sectors involved in constructing new natural gas-fired electric generating capacity; and
7. Natural gas extraction.

While the theoretical framework laid out by Berman and Bui (2001) still holds for the industries affected under the final ELGs, important differences in the markets and regulatory settings analyzed in their study and the setting presented here lead us to conclude that it is inappropriate to utilize their quantitative estimates to estimate the employment impacts from this proposed regulation. In particular, the industries used in these two studies as well as the timeframe (late 1970's to early 1990's) are quite different than those in the final ELG rule. Furthermore, the control strategies analyzed for this RIA—water treatment systems using chemical

[87] For more information, see: http://yosemite.epa.gov/sab/sabproduct.nsf/0/07E67CF77B54734285257BB0004F87ED?OpenDocument.

precipitation and biological treatment, ash conveyance systems, etc. —are very different from the control strategies examined by Berman and Bui. For these reasons we conclude there are too many uncertainties as to the transferability of the quantitative estimates from Berman and Bui to apply their estimates to quantify the employment impacts within the regulated sectors for this regulation, though these studies have usefulness for qualitative assessment of employment impacts.

Therefore, EPA first qualitatively describes potential employment impacts for the first three of these sectors: coal-fired steam electric power plants, pollution control suppliers, and virgin material suppliers. EPA then estimates employment effects at coal-fired steam electric power plants based on (1) the estimated labor required to operate and maintain the compliance equipment that is expected to be installed at these plants to comply with the rule, and (2) estimated decreases in the quantity of electricity generated by these plants and associated employment effects. This latter analysis of effects among coal-fired steam electric power plants is based on the Integrated Planning Model (IPM) analysis of the final ELG rule's market-level effects (based on analysis of Option D; see *Chapter 5*). In addition, EPA uses IPM output to estimate labor effects for coal mining, natural gas extraction, natural gas-fired generating plants, and the sectors involved in constructing new gas power plants.

6.2.1 Estimated Employment Effects in Coal-Fired Electric Power Plants Affected by the Steam Electric ELGs

As described above, the ELG final rule will have two broad categories of effect on the coal-fired power plants affected by the final rule:

1. Coal-fired plants that are affected by the rule are expected to install and operate compliance technology, which may lead to increased employment in these plants.
2. Coal-fired plants may generate less electricity than would otherwise occur in the absence of the rule due to increased production costs. In addition, some plants may retire earlier than would otherwise occur. These effects may lead to lower employment.

IPM projects that total coal-fired generating capacity is expected to decrease by approximately 0.6 percent in years 2020, 2025, and 2030 due to the ELG final rule.[88] In addition, IPM projects the final rule will lead to early retirement of 843 MW of coal-fired capacity by the year 2030 compared to the baseline. The 843 MW approximates to a net nationwide retirement of four generating units nationwide, or 0.2 percent of the total steam electric generation capacity in the baseline.

Changes in employment due to operation and maintenance of compliance technology

Given the relatively small effect of the ELG final rule on total capacity and generating unit retirements described above, EPA expects any decrease in labor in the steam electric generating industry to be small (see the following section for discussion of these effects). Additional changes in employment may occur, however, due to incorporation of pollution controls. As summarized in *Chapter 3*, EPA estimated that approximately 60 percent of the annualized compliance costs for the final rule are annualized capital costs. These capital costs are not expected to significantly affect employment at steam electric power plants themselves, but could increase employment in industries that manufacture and install equipment (for a discussion on those effects, see *Section 6.2.2* below).

The remaining costs consist of O&M costs, including labor costs for the maintenance, repair, and operations of wastewater treatment equipment. Some of these O&M costs translate to potential employment gains in the

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

regulated industry. The TDD describes the methodology EPA used to estimate plant-specific costs for each wastestream addressed in the final ELG rule, including estimates of the O&M labor hours required to operate and maintain the treatment technologies. For this analysis, EPA summed those labor hours over the plants and wastestreams to estimate the employment effects.

As discussed above, this analysis only considers the O&M costs incurred by coal-fired plants affected by the steam electric ELGs, and does not include changes in sectors that supply O&M-related inputs to these plants. Changes in employment are expressed in full-time equivalents (FTE), the number of total hours worked divided by the maximum number of compensable hours in a full-time schedule. Therefore, an FTE of 1.0 is equivalent to the work conducted by one full-time employee over the course of a year. While FTE is a measure of labor, changes in FTEs is not equivalent to the number of jobs added or lost within in a given sector. For example, employees can transition between full- and part-time, work overtime, transition between job functions, etc.

Table 6-1 presents the estimated annual labor requirements, in FTE, for coal-fired power plants to operate and maintain equipment to meet the final ELG limits (based on Option D). Note that these estimates assume implementation of the technologies at all steam electric plants; they do not include adjustments for projected changes in generation discussed above (including the net retirement of coal fired generating units).

Table 6-1: Estimated Annual Employment Effect for Coal-Fired Plants to Operate and Maintain Equipment to Meet the Final ELGs

Wastestream	Total Labor Hours	Annual FTE[a]
Bottom Ash	3,199,713	1,538
Fly Ash	65,269	31
FGD	875,450	421
Total	**4,140,433**	**1,991**

[a] FTE measures labor, but does not directly equate to job gains or losses
Source: U.S. EPA Analysis, 2015.

Changes in employment due to reduced electricity generation by coal-fired power plants

The IPM analysis of the final ELG's market-level effects provides estimates of changes in generation from steam electric power plants due both to reduced generation by generating units that continue operation after meeting the ELGs and those that cease operation earlier than otherwise anticipated in the baseline as a result of the rule. Based on the IPM estimates of these changes in coal fired generation capacity, EPA estimated that the final rule will reduce total O&M labor at coal-fired electricity plants by 835 FTEs by the year 2030 (see *Table 6-2*, below). As discussed above, the estimated changes in FTEs do not necessarily translate to the number of jobs added or lost within a given sector. For comparison, in 2013, the fossil fuel electric power generation sector reported 72,760 employees.[89]

Table 6-2: Estimated O&M Labor Impacts at Steam Electric Power Generating Plants Due to the Final ELGs (FTEs)[a]

	2020	2025	2030
Change in labor at coal-fired power plants	-953	-867	-835

[a] FTE measures labor, but does not directly equate to job gains or losses
Source: U.S. EPA Analysis, 2015.

[89] From 2013 County Business Patterns for NAICS 221112.

6.2.2 Wastewater Treatment Systems Suppliers

The compliance costs incurred by coal-fired power plants are primarily capital investments for goods and services needed to meet the final ELGs. These costs to the regulated industry translate into increased demand to the firms manufacturing and installing the equipment and could potentially spur increased employment in those industries.

Section 3.1.2 summarizes the capital cost of compliance equipment used in meeting the final ELGs. Chapters 7 and 9 in the *TDD* details the equipment and systems EPA assumed when calculating plant-specific costs of meeting the final ELGs for each wastestream (pumps, tanks, chemical feed systems, mixers, reactors, clarifiers, filter presses, sand filters, buildings, etc.). The total annualized capital costs for Option D are $204.4 million ($2013, after-tax). This value includes the cost to design the compliance system, and manufacture and install the needed compliance equipment, as well as any other upfront costs associated with meeting the final ELGs. The demand for these products and services could translate into positive employment effects in the supplying industries as equipment is purchased by steam electric plants needing to upgrade their systems to meet the final rule limits. The extent of such effects will depend on the domestic labor intensity of these activities

6.2.3 Estimated Employment Effects in Virgin Material Supplier Industries

EPA expects the final ELG rule to enhance the marketability of coal combustion residuals (CCR), such as fly ash, through conversions from wet to dry handling. As a result, EPA estimated that steam electric power plants may market a greater amount of their CCR to beneficial uses rather than dispose of it in impoundments or landfills. Chapter 10 of the *BCA* document describes EPA's analysis of the amount of CCR that may be marketed for beneficial uses, based on the amount of CCR handled dry instead of wet and demand present within the state where the plant operates. Specifically, EPA estimated changes in the amount of fly ash used in concrete production and fill, and the amount of bottom ash used in fill.

The increased beneficial use of CCR means that manufacturers of concrete and fill will reduce their demand for virgin raw materials and substitute with CCR, which could reduce employment in firms that manufacture and distribute the affected virgin raw materials. EPA estimates that increased marketing of CCR prompted by the final rule will reduce domestic production of Portland cement and virgin fill raw materials by approximately $35 million ($2013) in annual revenue value (*Table 6-3*). EPA calculated this value based on the estimated displacement of virgin material by use of CCR (annual tonnage) due to the final ELG rule and the price per ton of this material. This reduction may, in turn, lead to reduced employment in the industries that produce these virgin materials. The extent of this employment reduction will depend on the labor intensity of these production activities. For comparison purposes, *Table 6-3* also provides the total value of shipments of virgin materials.

Table 6-3: Estimated Annual Reduction in Revenue to Virgin Material Suppliers from Increased Beneficial Use of CCR Due to the Final ELGs [a]

Impact Estimation Metrics	Concrete	Structural Fill
Average annual future increase in tons of beneficially used CCRs due to the ELG final rule	162,491	4,929,131
Price per ton of virgin raw materials[b]	$86.23	$4.32
Annual revenue reduction to raw material suppliers	**$14,011,590**	**$21,293,846**
Total value of shipments of virgin materials[c]	$6,094,556,255	$717,846,397

Notes:

[a] Chapter 10 of the BCA describes EPA estimates of induced future increase.

[b] Prices obtained from the 2012 USGS Minerals Yearbook and represent the average price over 2008-2012, expressed in 2013 dollars.

[c] Values from 2012 Economic Census (Census, 2012), deflated to 2013 dollars.
Source: U.S. EPA Analysis, 2015.

To estimate the employment effect of these reduced purchases, EPA calculated the labor intensity (FTE per $million in value of production, measured here as revenue) of the virgin material industries in which production would be expected to decline because of the final ELG rule, and multiplied these values by the estimated reduction in purchases from these industries. To calculate the labor intensity values, EPA first identified the industries (Cement Manufacturing, NAICS 327310, and Fill Dirt Pits Mining and/or Beneficiating, NAICS 212399) that would be expected to reduce purchases of virgin product-based materials displaced by beneficially used CCR resulting from the final ELG rule. Second, using data from the 2007 Economic Census, EPA identified the industries whose production would be displaced by beneficial use of CCR in the Cement Manufacturing and Fill Dirt Pits Mining and/or Beneficiating industries, resulting from the final ELG rule. EPA identified six industries as the affected suppliers to the Cement Manufacturing industry and seven industries as the affected suppliers to the Fill Dirt Pits Mining and/or Beneficiating industry. These industries are listed in *Table 6-4.* Last, EPA calculated the labor intensity in these industries by dividing the number of employees by annual revenue, and then calculated the total effects by weighting the delivered cost of material from affected supplier industries to industries using CCR as substitute. *Table 6-4* reports the resulting labor intensity values for the affected supplier industries.

Table 6-4: Labor Intensity in Virgin Material Supplier Industries Affected by Increased Beneficial Use of CCR Due to the Final ELGs

Industries Using CCR As Substitute for Virgin Material-Based Inputs	Industries Supplying Virgin Material-Based Inputs (Affected Supplier Industries)	Employees in Affected Supplier Industries	Revenue in Affected Supplier Industries (million 2007$)	Labor Intensity in Affected Supplier Industries (FTE per million 2007$)
Cement Manufacturing (NAICS 327310)	Paper shipping sacks & multiwall bags (NAICS 322224)	10,415	$2,369	4.40
	Clay & non-clay refractories (NAICS 327120)	30,546	$6,213	4.92
	Minerals & earths, ground or otherwise treated (NAICS 327992)	6,649	$3,131	2.12
	Other stone, clay, glass & concrete products (NAICS 327999)	9,801	$3,320	2.95
	Abrasives & abrasive products (NAICS 327910)	14,202	$4,535	3.13
	Crushed & broken stone (NAICS 21231)	53,827	$15,170	3.55
			Total[a]	**3.09**
Fill Dirt Pits Mining and/or Beneficiating (NAICS 212399)	Crude minerals received for preparation (NAICS 212390)	10,388	$3,820	2.72
	Purchased machinery installed, incl. mobile loading, transport/other equip. (NAICS 333999)	51,057	$11,448	4.46
	Industrial chemicals (chemical reagents, acidizing mat, etc.) (NAICS 3259)	84,388	$39,389	2.14
	Explosive materials (NAICS 325920)	6,532	$1,745	3.74
	Steel shapes & forms, excluding castings & forgings (NAICS 33122)	26,881	$12,680	2.12
	Distillate grade #1, 2, 4, & light diesel fuel used as fuel plus #5 & 6 & heavy diesel fuel used as fuel (NAICS 324110)	64,839	$580,020	0.11
	Gas (natural, manufactured & mixed) as a fuel (NAICS 211110)	150,443	$255,105	0.59
			Total[a]	**2.88**

Notes:
Data from 2007 Economic Census (U.S. DOC, 2012).
a. Total labor intensity value weighted based on delivered cost of material from affected supplier industries to industries using CCR as substitute.
Source: U.S. EPA Analysis, 2015.

As the final step in this calculation, EPA multiplied the labor intensity values for the affected supplier industries by the estimated reduction in purchases from these industries, due to the final ELG rule. *Table 6-5* reports the estimated potential reduction in employment due to increased beneficial use of CCR and correspondingly displaced production of virgin material-based inputs.

Table 6-5: Potential Reduction in Employment in Virgin Material Supplier Industries Due to Increased Beneficial Use of CCR Under the Final ELGs

Industries Using CCR As Substitute for Virgin Material-Based Inputs	Potential Revenue Reduction in Affected Supplier Industries[a] (million 2013$)	Labor Intensity in Affected Supplier Industries (FTE per million 2007$)	Labor Intensity in Affected Supplier Industries (FTE per million 2013$)[b]	Potential Reduction in Employment in Affected Supplier Industries (FTE)
Cement Substitute in Concrete	$14.01	3.09	2.82	40
Structural Fill	$21.29	2.88	2.63	56
			Total	**96**

Notes:

[a] See *Table 6-3*.

[b] See *Table 6-4*. EPA restated the labor intensity values in *Table 6-4* from 2007$ to 2013$ using the GDP deflator (1.095)
Source: U.S. EPA Analysis, 2015.

6.2.4 Coal Mining and Natural Gas Extraction

This analysis uses the results from IPM to estimate labor effects in the coal mining and natural gas extraction industries. As noted above, results are reported as FTEs, which are not equivalent to the number of jobs added or lost within in a given sector. *Table 6-6* shows the estimated labor effects of the final ELG rule on coal mining and natural gas extraction.

The IPM analysis of the final ELG rule provides estimates of the changes in coal usage (in million short tons per year, or MT) and natural gas usage (in millions of BTUs, or MMBTU), in 2020, 2025 and 2030. The changes in direct labor in the fuel sector are calculated using (1) the IPM-based estimates of changes in fuel use and (2) data on labor productivity in the relevant fuel production sectors.

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). EPA estimated corresponding changes in FTEs using U.S. Energy Information Administration (EIA) data on regional coal mining productivity (in short tons per employee hour), using 2008 labor productivity estimates.[90]

For natural gas demand, labor productivity per unit of natural gas produced was unavailable, unlike coal labor productivities used above. Most secondary data sources (such as Census and EIA) provide estimates for the combined oil and gas extraction sector. The natural gas labor analysis, therefore, used an adjusted labor productivity estimate for the combined oil and gas sector, which accounts for the relative contributions of oil and natural gas in total sector output (in terms of energy output in million Btu). EPA then used this estimate of labor productivity with the incremental natural gas demand from the IPM run to estimate the FTE effects for specific analysis years (converting the TCF of gas used projected by IPM into million Btu using the appropriate conversion factors). Labor used to construct pipelines associated with the increase in natural gas production is not included in this estimate.[91]

[90] From EIA Annual Energy Review, Coal Mining Productivity Data (U.S. DOE, 2011)

[91] For comparison, the 2007 Economic Census reported 77,435 employees in the coal mining sector and 7,389 employees in the natural gas extraction sector. (U.S. DOC, 2007).

Table 6-6: Estimated Coal Mining and Natural Gas Extraction Labor Impact Due to the ELG Final Rule (FTEs)[a]

Fuel Extraction Activity Category	2020	2025	2030
Total Coal Mining Labor	**-525**	**-213**	**-168**
Midwest Basin	10	-205	-185
Western Basin	5	13	16
Appalachian	-540	-21	1
Total Natural Gas Extraction Labor	**160**	**51**	**15**

[a] FTE measures labor, but does not directly equate to job gains or losses
Source: U.S. EPA Analysis, 2015.

6.2.5 Natural Gas Power Plants

The IPM-based labor analysis also considers potential labor effects at power plants that generate electricity using natural gas. EPA analyzed changes in labor needed to operate and maintain new gas-fired generating units using the relevant O&M annual labor factors from EPA's analysis of the proposed CPP rule (U.S. EPA, 2014). In the analysis of the CPP rule, EPA estimated that O&M at gas-fired generating units annually required 227.3 FTE per GW of capacity. EPA used this value to estimate the changes in O&M labor needs of the final ELG rule in 2020, 2025 and 2030. *Table 6-7* summarizes the results.

As noted above, these results are reported as FTEs, which are not equivalent to the number of jobs added or lost within a given sector.

Table 6-7: Estimated O&M Labor Impact at Natural Gas Power Plants Due to the Final ELGs (FTEs)[a]

Activity Category	2020	2025	2030
Total labor at gas powered plants	253	207	191

[a] FTE measures labor, but does not directly equate to job gains or losses
Source: U.S. EPA Analysis, 2015.

6.2.6 Sectors Associated with Construction of Additional Natural Gas-Fired Generating Capacity

The IPM analysis for the final ELG rule finds that electricity generators will construct additional natural gas fired capacity beyond that otherwise estimated to occur absent the ELGs. Adding new natural gas-fired capacity will require additional labor to manufacture and install this additional capacity. EPA estimated the direct labor for installing new combined cycle natural gas-fired generating units due to the final ELG rule from the labor requirement estimates for new natural-gas units presented in the Agency's analysis for the 2014 CCR rule (U.S. EPA, 2014).

The analysis for the CCR rule indicates that 827.3 job-years are needed in each of 3 years to construct 1 GW of new natural gas generating capacity (for a total of 2,481.9 job-years per GW constructed). EPA used this labor factor to estimate the labor requirements for constructing the additional natural gas-fired capacity estimated to occur due to the final ELG rule through the 2030 run year (*i.e.*, 2033). *Table 6-8* shows the estimated labor effects of the final ELG rule due to construction of new natural gas capacity, measured in FTEs.

Table 6-8: Estimated Labor Impact from Construction of New Natural Gas Capacity Due to the Final ELGs (FTEs)[a]

Activity Category	2030
Change in cumulative natural gas capacity addition due to the final ELG rule (GW)	0.92
Cumulative new gas generating capacity construction labor (FTEs*)	2,283
Annual average FTEs over analysis period (2016-2033)	127

[a] FTE measures labor, but does not directly equate to job gains or losses
Source: U.S. EPA Analysis, 2015.

6.3 Findings

In conclusion, deriving estimates of 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. Effects on labor demand in the environmental protection sector seem likely to be positive. And new evidence suggests that environmental regulation may improve labor supply and productivity.

Using a bottoms-up engineering approach, EPA provides partial employment impact estimates at coal-fired steam electric power plants as well as for coal mining, natural gas extraction, natural gas-fired generating plants, and the sectors involved in constructing new gas power plants. Even though this final ELG rule affected many sectors, the overall job impacts, both positive and negative, are quite small. Furthermore, this employment evaluation does not reach a quantitative estimate of the overall employment effects of the final rule on employment or even whether the net effect will be positive or negative. However, given that the expected increase in production costs for coal-fired generation is relatively small (0.6 percent, based on IPM projections of Option D for 2030), the magnitude of all effects combined could also be expected to be small.

7 Assessment of Potential Electricity Price Effects

7.1 Analysis Overview

As part of its assessment of the cost and economic impact of the final ELG and other regulatory options that EPA evaluated (defined in *Chapter 1: Introduction* and discussed elsewhere in this document), EPA assessed the potential impacts on electricity prices. The Agency conducted this analysis 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 assumes no changes in baseline operating characteristics of steam electric power plants in response to regulatory requirements. 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 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,[92] EPA judges that this assumption is 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 not be relevant because the two conditions (full cost pass-through and no cost pass-through) could not simultaneously occur for the same steam electric power plant.

92 As discussed in *Chapter 2: Profile of the Electric Power Industry*, 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

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, EPA assumed that compliance costs would be fully passed through as increased electricity prices and allocated these costs among consumer groups in proportion to the baseline quantity of electricity consumed by each group. 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.[93,94] The steps in this calculation are as follows:

- EPA summed weighted pre-tax plant-level annualized compliance costs in 2015 by NERC region.[95, 96]
- EPA estimated the approximate average price impact per unit of electricity consumption by dividing total compliance costs by the projected total MWh of sales in 2015 by NERC region, from AEO2013. EPA followed this approach for all NERC regions containing plants expected to incur compliance costs (*e.g.*, excluding Alaska System Coordinating Council (ASCC) and Hawaii Coordinating Council (HICC)).
- EPA compared the estimated average price effect to the projected electricity price by consumer group and NERC region for 2015 from AEO2013 for all NERC regions except, again, for ASCC and HICC. To estimate average electricity rate by consumer group for ASCC and HICC, EPA divided electricity revenue by electricity sales (MWh) reported by consumer group in the 2012 EIA-861 database.

7.2.2 Key Findings for Regulatory Options

As reported in *Table 7-1*, annualized compliance costs (in cents per KWh sales) are zero in ASCC and HICC regions for all options. The costs per unit of sale are highest in the SERC and RFC regions for all five options analyzed. On average, across the United States, Option A results in the lowest cost of 0.003¢ per KWh, while Option E results in the highest cost of 0.015¢ per KWh. The final BAT and PSES (Option D) result in national costs of 0.013¢ per KWh.

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93 As discussed in *Chapter 2*, some NERC regions have been re-defined/re-named over the past few years; the NERC region definitions used in the final ELG analyses vary by analysis depending on which region definition aligns better with the data elements underlying the analysis.

94 NERC is responsible for the overall reliability, planning, and coordination of the power grids; it is organized into regional councils that are responsible for the overall coordination of bulk power policies that affect their regions' reliability and quality of service (see *Chapter 2*).

95 These compliance costs are in 2013 dollars as of a given technology implementation year (2019 through 2023) and discounted to 2015 at 7 percent. This analysis accounts for the different years in which plants are expected 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 (2019 through 2023) and then discounting these effects to a single analysis year (2015) accounts for this consideration.

96 For this analysis, 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 Regulatory Option in 2015 ($2013)[a]

NERC Region	Total Electricity Sales (at 2015; MWh)	Annualized Pre-Tax Compliance Costs (at 2015; $2013)	Costs per Unit of Sales (2013¢/KWh Sales)
Option A			
ASCC	6,288,931	$0	¢0.000
FRCC	210,529,236	$126,329	¢0.000
HICC	9,639,157	$0	¢0.000
MRO	208,620,000	$2,490,716	¢0.001
NPCC	260,550,000	$0	¢0.000
RFC	866,450,000	$34,937,118	¢0.004
SERC	1,009,880,000	$81,437,712	¢0.008
SPP	196,820,000	$1,521,839	¢0.001
TRE	313,222,656	$1,062,881	¢0.000
WECC	670,710,000	$317,118	¢0.000
U.S.	**3,752,709,980**	**$121,893,713**	**¢0.003**
Option B			
ASCC	6,288,931	$0	¢0.000
FRCC	210,529,236	$1,312,331	¢0.001
HICC	9,639,157	$0	¢0.000
MRO	208,620,000	$3,896,107	¢0.002
NPCC	260,550,000	$0	¢0.000
RFC	866,450,000	$73,851,493	¢0.009
SERC	1,009,880,000	$119,277,776	¢0.012
SPP	196,820,000	$3,808,886	¢0.002
TRE	313,222,656	$1,726,155	¢0.001
WECC	670,710,000	$317,118	¢0.000
U.S.	**3,752,709,980**	**$204,189,865**	**¢0.005**
Option C			
ASCC	6,288,931	$0	$0.000
FRCC	210,529,236	$1,312,331	$0.001
HICC	9,639,157	$0	$0.000
MRO	208,620,000	$11,683,376	$0.006
NPCC	260,550,000	$0	$0.000
RFC	866,450,000	$192,385,843	$0.022
SERC	1,009,880,000	$176,731,271	$0.018
SPP	196,820,000	$15,897,187	$0.008
TRE	313,222,656	$1,730,340	$0.001
WECC	670,710,000	$317,118	$0.000
U.S.	**3,752,709,980**	**$400,057,466**	**$0.011**
Option D			
ASCC	6,288,931	$0	¢0.000
FRCC	210,529,236	$1,312,331	¢0.001
HICC	9,639,157	$0	¢0.000
MRO	208,620,000	$28,672,431	¢0.014
NPCC	260,550,000	$1,006,148	¢0.000
RFC	866,450,000	$230,647,410	¢0.027
SERC	1,009,880,000	$196,526,405	¢0.019
SPP	196,820,000	$26,283,895	¢0.013
TRE	313,222,656	$1,730,340	¢0.001
WECC	670,710,000	$9,989,162	¢0.001
U.S.	**3,752,709,980**	**$496,168,123**	**¢0.013**

Table 7-1: Compliance Cost per KWh Sales by NERC Region and Regulatory Option in 2015 ($2013)[a]

NERC Region	Total Electricity Sales (at 2015; MWh)	Annualized Pre-Tax Compliance Costs (at 2015; $2013)	Costs per Unit of Sales (2013¢/KWh Sales)
	Option E		
ASCC	6,288,931	$0	¢0.000
FRCC	210,529,236	$1,312,331	¢0.001
HICC	9,639,157	$0	¢0.000
MRO	208,620,000	$32,580,617	¢0.016
NPCC	260,550,000	$1,477,964	¢0.001
RFC	866,450,000	$264,323,058	¢0.031
SERC	1,009,880,000	$208,867,320	¢0.021
SPP	196,820,000	$31,463,167	¢0.016
TRE	313,222,656	$3,888,177	¢0.001
WECC	670,710,000	$9,989,162	¢0.001
U.S.	**3,752,709,980**	**$553,901,796**	**¢0.015**

a. The rate impact analysis assumes full pass-through of all compliance costs to electricity consumers.
Source: U.S. EPA Analysis, 2015; U.S. DOE, 2014a; U.S. DOE, 2012d.

To determine the relative significance of compliance costs on electricity prices across consumer groups, EPA compared the per KWh compliance cost to baseline retail electricity prices by consuming group, and for the average of the groups. As reported in *Table 7-2*, across the United States, Option A is estimated to result in the smallest electricity price increase relative to baseline electricity prices, 0.03 percent, while Option E is estimated to yield the largest increase of approximately 0.16 percent. The final BAT and PSES (Option D) are estimated to result in an approximate 0.14 percent increase in electricity prices.

Looking across the four consumer groups and assuming that any price increase would apply equally to all consumer groups, industrial consumers are estimated to experience the highest price increases relative to their baseline electricity price, while residential consumers are estimated to experience the lowest price increases, again relative to their baseline electricity price. For example, for Option D, the 0.013 ¢/KWh represents 0.21 percent of the baseline electricity price for industrial consumers, and 0.11 percent of that for residential consumers. The higher relative price increase for industrial consumers is due to the lower baseline electricity rates paid by industrial consumers and EPA's assumption of uniform increase across all consumer groups; it does not reflect differential distribution of the incremental costs across consumer groups.

Table 7-2: Projected 2015 Price (Cents per KWh of Sales) and Potential Price Increase Due to Compliance Costs by NERC Region and Regulatory Option ($2013)[a]

NERC Region	Compliance Cost (¢/KWh)	Residential		Commercial		Industrial		Transportation		All Sector Average	
		Baseline Price	% Change	Baseline Price	% Change	Baseline Price	% Change	Baseline Price	% Change	Baseline Price	% Change
				Option A							
ASCC	¢0.000	$17.58	0.00%	$17.58	0.00%	$17.58	0.00%	$17.58	0.00%	$17.58	0.00%
FRCC	¢0.000	$11.24	0.00%	$9.25	0.00%	$8.04	0.00%	$8.96	0.00%	$10.16	0.00%
HICC	¢0.000	$37.90	0.00%	$37.90	0.00%	$37.90	0.00%	$37.90	0.00%	$37.90	0.00%
MRO	¢0.001	$10.52	0.01%	$8.11	0.01%	$5.94	0.02%	$7.77	0.02%	$8.06	0.01%
NPCC	¢0.000	$18.10	0.00%	$13.69	0.00%	$8.87	0.00%	$13.48	0.00%	$14.51	0.00%
RFC	¢0.004	$12.59	0.03%	$10.40	0.04%	$6.75	0.06%	$9.96	0.04%	$10.03	0.04%
SERC	¢0.008	$10.20	0.08%	$8.78	0.09%	$5.79	0.14%	$8.21	0.10%	$8.39	0.10%
SPP	¢0.001	$9.47	0.01%	$7.89	0.01%	$5.59	0.01%	$7.68	0.01%	$7.78	0.01%

Table 7-2: Projected 2015 Price (Cents per KWh of Sales) and Potential Price Increase Due to Compliance Costs by NERC Region and Regulatory Option ($2013)[a]

NERC Region	Compliance Cost (¢/KWh)	Residential		Commercial		Industrial		Transportation		All Sector Average	
		Baseline Price	% Change	Baseline Price	% Change	Baseline Price	% Change	Baseline Price	% Change	Baseline Price	% Change
TRE	¢0.000	$10.82	0.00%	$6.84	0.00%	$5.12	0.01%	$8.51	0.00%	$7.89	0.00%
WECC	¢0.000	$12.08	0.00%	$10.99	0.00%	$6.95	0.00%	$10.14	0.00%	$10.38	0.00%
US	**¢0.003**	**$11.65**	**0.03%**	**$9.77**	**0.03%**	**$6.30**	**0.05%**	**$10.51**	**0.03%**	**$9.48**	**0.03%**
Option B											
ASCC	¢0.000	$17.58	0.00%	$17.58	0.00%	$17.58	0.00%	$17.58	0.00%	$17.58	0.00%
FRCC	¢0.001	$11.24	0.01%	$9.25	0.01%	$8.04	0.01%	$8.96	0.01%	$10.16	0.01%
HICC	¢0.000	$37.90	0.00%	$37.90	0.00%	$37.90	0.00%	$37.90	0.00%	$37.90	0.00%
MRO	¢0.002	$10.52	0.02%	$8.11	0.02%	$5.94	0.03%	$7.77	0.02%	$8.06	0.02%
NPCC	¢0.000	$18.10	0.00%	$13.69	0.00%	$8.87	0.00%	$13.48	0.00%	$14.51	0.00%
RFC	¢0.009	$12.59	0.07%	$10.40	0.08%	$6.75	0.13%	$9.96	0.09%	$10.03	0.08%
SERC	¢0.012	$10.20	0.12%	$8.78	0.13%	$5.79	0.20%	$8.21	0.14%	$8.39	0.14%
SPP	¢0.002	$9.47	0.02%	$7.89	0.02%	$5.59	0.03%	$7.68	0.03%	$7.78	0.02%
TRE	¢0.001	$10.82	0.01%	$6.84	0.01%	$5.12	0.01%	$8.51	0.01%	$7.89	0.01%
WECC	¢0.000	$12.08	0.00%	$10.99	0.00%	$6.95	0.00%	$10.14	0.00%	$10.38	0.00%
US	**¢0.005**	**$11.65**	**0.05%**	**$9.77**	**0.06%**	**$6.30**	**0.09%**	**$10.51**	**0.05%**	**$9.48**	**0.06%**
Option C											
ASCC	¢0.000	$17.58	0.00%	$17.58	0.00%	$17.58	0.00%	$17.58	0.00%	$17.58	0.00%
FRCC	¢0.001	$11.24	0.01%	$9.25	0.01%	$8.04	0.01%	$8.96	0.01%	$10.16	0.01%
HICC	¢0.000	$37.90	0.00%	$37.90	0.00%	$37.90	0.00%	$37.90	0.00%	$37.90	0.00%
MRO	¢0.006	$10.52	0.05%	$8.11	0.07%	$5.94	0.09%	$7.77	0.07%	$8.06	0.07%
NPCC	¢0.000	$18.10	0.00%	$13.69	0.00%	$8.87	0.00%	$13.48	0.00%	$14.51	0.00%
RFC	¢0.022	$12.59	0.18%	$10.40	0.21%	$6.75	0.33%	$9.96	0.22%	$10.03	0.22%
SERC	¢0.018	$10.20	0.17%	$8.78	0.20%	$5.79	0.30%	$8.21	0.21%	$8.39	0.21%
SPP	¢0.008	$9.47	0.09%	$7.89	0.10%	$5.59	0.14%	$7.68	0.11%	$7.78	0.10%
TRE	¢0.001	$10.82	0.01%	$6.84	0.01%	$5.12	0.01%	$8.51	0.01%	$7.89	0.01%
WECC	¢0.000	$12.08	0.00%	$10.99	0.00%	$6.95	0.00%	$10.14	0.00%	$10.38	0.00%
US	**¢0.011**	**$11.65**	**0.09%**	**$9.77**	**0.11%**	**$6.30**	**0.17%**	**$10.51**	**0.10%**	**$9.48**	**0.11%**
Option D											
ASCC	¢0.000	$17.58	0.00%	$17.58	0.00%	$17.58	0.00%	$17.58	0.00%	$17.58	0.00%
FRCC	¢0.001	$11.24	0.01%	$9.25	0.01%	$8.04	0.01%	$8.96	0.01%	$10.16	0.01%
HICC	¢0.000	$37.90	0.00%	$37.90	0.00%	$37.90	0.00%	$37.90	0.00%	$37.90	0.00%
MRO	¢0.014	$10.52	0.13%	$8.11	0.17%	$5.94	0.23%	$7.77	0.18%	$8.06	0.17%
NPCC	¢0.000	$18.10	0.00%	$13.69	0.00%	$8.87	0.00%	$13.48	0.00%	$14.51	0.00%
RFC	¢0.027	$12.59	0.21%	$10.40	0.26%	$6.75	0.39%	$9.96	0.27%	$10.03	0.27%
SERC	¢0.019	$10.20	0.19%	$8.78	0.22%	$5.79	0.34%	$8.21	0.24%	$8.39	0.23%
SPP	¢0.013	$9.47	0.14%	$7.89	0.17%	$5.59	0.24%	$7.68	0.17%	$7.78	0.17%
TRE	¢0.001	$10.82	0.01%	$6.84	0.01%	$5.12	0.01%	$8.51	0.01%	$7.89	0.01%
WECC	¢0.001	$12.08	0.01%	$10.99	0.01%	$6.95	0.02%	$10.14	0.01%	$10.38	0.01%
US	**¢0.013**	**$11.65**	**0.11%**	**$9.77**	**0.14%**	**$6.30**	**0.21%**	**$10.51**	**0.13%**	**$9.48**	**0.14%**

Table 7-2: Projected 2015 Price (Cents per KWh of Sales) and Potential Price Increase Due to Compliance Costs by NERC Region and Regulatory Option ($2013)[a]

NERC Region	Compliance Cost (¢/KWh)	Residential		Commercial		Industrial		Transportation		All Sector Average	
		Baseline Price	% Change	Baseline Price	% Change	Baseline Price	% Change	Baseline Price	% Change	Baseline Price	% Change
Option E											
ASCC	¢0.000	$17.58	0.00%	$17.58	0.00%	$17.58	0.00%	$17.58	0.00%	$17.58	0.00%
FRCC	¢0.001	$11.24	0.01%	$9.25	0.01%	$8.04	0.01%	$8.96	0.01%	$10.16	0.01%
HICC	¢0.000	$37.90	0.00%	$37.90	0.00%	$37.90	0.00%	$37.90	0.00%	$37.90	0.00%
MRO	¢0.016	$10.52	0.15%	$8.11	0.19%	$5.94	0.26%	$7.77	0.20%	$8.06	0.19%
NPCC	¢0.001	$18.10	0.00%	$13.69	0.00%	$8.87	0.01%	$13.48	0.00%	$14.51	0.00%
RFC	¢0.031	$12.59	0.24%	$10.40	0.29%	$6.75	0.45%	$9.96	0.31%	$10.03	0.30%
SERC	¢0.021	$10.20	0.20%	$8.78	0.24%	$5.79	0.36%	$8.21	0.25%	$8.39	0.25%
SPP	¢0.016	$9.47	0.17%	$7.89	0.20%	$5.59	0.29%	$7.68	0.21%	$7.78	0.21%
TRE	¢0.001	$10.82	0.01%	$6.84	0.02%	$5.12	0.02%	$8.51	0.01%	$7.89	0.02%
WECC	¢0.001	$12.08	0.01%	$10.99	0.01%	$6.95	0.02%	$10.14	0.01%	$10.38	0.01%
US	**¢0.015**	**$11.65**	**0.13%**	**$9.77**	**0.15%**	**$6.30**	**0.23%**	**$10.51**	**0.14%**	**$9.48**	**0.16%**

a. The rate impact analysis assumes full pass-through of all compliance costs to electricity consumers.
Sources: U.S. EPA Analysis, 2015; U.S. DOE, 2014a; U.S. DOE, 2012d.

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 final ELGs 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.

As discussed in *Chapter 3*, the compliance costs used in this analysis reflect anticipated unit retirements, conversions, and repowerings announced through August 2014 and scheduled to occur by 2023, and include projected conversions to dry systems in response to the final CCR rule. As discussed in *Chapter 3*, projected changes that may result from the CPP rule are based on EPA's understanding of those effects at the time the ELG analyses were conducted, based on the proposed CPP rule analysis. To the extent that unit retirements, conversions, and repowerings resulting from the final CPP rule differ from anticipated changes, total annualized compliance costs may differ from actual costs.

7.3 Assessment of Impact of Compliance Costs on Household Electricity Costs

As an additional measure of the potential cost and economic impact of the final ELGs on electricity consumers, EPA assessed the potential increases in the cost of electricity to residential households.

7.3.1 Analysis Approach and Data Inputs

For this analysis, 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. 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. 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, EPA summed weighted pre-tax, plant-level annualized compliance costs in 2015 by NERC region.[97]
- As was done for the analysis of impact of compliance costs on electricity prices, EPA divided total compliance costs by the total MWh of sales reported for each NERC region. For all NERC regions except ASCC and HICC, EPA used electricity sales (in MWh) for 2015 from AEO2013.[98] For ASCC and HICC, EPA used the historical quantity of electricity sales (in MWh) for the year 2012 from the 2012 EIA-861 database and assumed that total average electricity sales would remain unchanged through 2015.
- To calculate average annual electricity sales per household, EPA divided the total quantity of *residential* sales (in MWh) for 2012 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 for all NERC regions from the 2012 EIA-861 database. For this analysis, EPA assumed that the average quantity of electricity sales per household by NERC region would remain the same in 2015 as in 2012.
- To assess the potential annual cost impact per household, EPA multiplied the estimated average price impact by the average quantity of electricity sales per household in 2012 by NERC region.

7.3.2 Key Findings for Regulatory Options

Table 7-3 reports the results of this analysis by NERC region for each option, and overall for the United States.

Average annual cost per residential household is zero in ASCC and HICC for all options. The average annual cost per residential household is generally highest in SERC, while regions facing the lowest non-zero cost vary (WECC and/or NPCC, depending on the option). In particular for the final BAT and PSES (Option D), results show the average annual cost per residential household increasing by $0.03 to $2.67 depending on the region (and excluding ASCC and HICC regions), with a national average of $1.42.

[97] These are the same cost estimates that were used for the electricity price impact analysis discussed in *Section 1.4*.

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

Table 7-3: Average Annual Cost per Household in 2015 by NERC Region and Regulatory Option ($2013)[a]

NERC Region	Total Annual Compliance Cost (at 2015; $2013)	Total Electricity Sales (at 2014; MWh)	Compliance Cost per Unit of Sales ($2013/MWh)	Residential Electricity Sales (at 2015; MWh)	Number of Households (at 2015)	Residential Sales per Residential Consumer (MWh)	Compliance Cost per Household ($2013)
Option A							
ASCC	$0	6,288,931	$0.00	2,117,367	267,167	7.93	$0.00
FRCC	$126,329	210,529,236	$0.00	105,233,155	8,121,801	12.96	$0.01
HICC	$0	9,639,157	$0.00	2,739,298	419,612	6.53	$0.00
MRO	$2,490,716	208,620,000	$0.01	56,124,684	5,530,600	10.15	$0.12
NPCC	$0	260,550,000	$0.00	102,150,404	13,620,886	7.50	$0.00
RFC	$34,937,118	866,450,000	$0.04	337,291,906	33,594,289	10.04	$0.40
SERC	$81,437,712	1,009,880,000	$0.08	351,008,786	25,921,554	13.54	$1.09
SPP	$1,521,839	196,820,000	$0.01	69,196,041	5,373,947	12.88	$0.10
TRE	$1,062,881	313,222,656	$0.00	68,217,998	4,976,747	13.71	$0.05
WECC	$317,118	670,710,000	$0.00	239,135,284	26,736,937	8.94	$0.00
U.S.	**$121,893,713**	**3,752,709,980**	**$0.03**	**1,333,214,923**	**124,563,540**	**10.70**	**$0.35**
Option B							
ASCC	$0	6,288,931	$0.00	2,117,367	267,167	7.93	$0.00
FRCC	$1,312,331	210,529,236	$0.01	105,233,155	8,121,801	12.96	$0.08
HICC	$0	9,639,157	$0.00	2,739,298	419,612	6.53	$0.00
MRO	$3,896,107	208,620,000	$0.02	56,124,684	5,530,600	10.15	$0.19
NPCC	$0	260,550,000	$0.00	102,150,404	13,620,886	7.50	$0.00
RFC	$73,851,493	866,450,000	$0.09	337,291,906	33,594,289	10.04	$0.86
SERC	$119,277,776	1,009,880,000	$0.12	351,008,786	25,921,554	13.54	$1.60
SPP	$3,808,886	196,820,000	$0.02	69,196,041	5,373,947	12.88	$0.25
TRE	$1,726,155	313,222,656	$0.01	68,217,998	4,976,747	13.71	$0.08
WECC	$317,118	670,710,000	$0.00	239,135,284	26,736,937	8.94	$0.00
U.S.	**$204,189,865**	**3,752,709,980**	**$0.05**	**1,333,214,923**	**124,563,540**	**10.70**	**$0.58**
Option C							
ASCC	$0	6,288,931	$0.00	2,117,367	267,167	7.93	$0.00
FRCC	$1,312,331	210,529,236	$0.01	105,233,155	8,121,801	12.96	$0.08
HICC	$0	9,639,157	$0.00	2,739,298	419,612	6.53	$0.00
MRO	$11,683,376	208,620,000	$0.06	56,124,684	5,530,600	10.15	$0.57
NPCC	$0	260,550,000	$0.00	102,150,404	13,620,886	7.50	$0.00
RFC	$192,385,843	866,450,000	$0.22	337,291,906	33,594,289	10.04	$2.23
SERC	$176,731,271	1,009,880,000	$0.18	351,008,786	25,921,554	13.54	$2.37
SPP	$15,897,187	196,820,000	$0.08	69,196,041	5,373,947	12.88	$1.04
TRE	$1,730,340	313,222,656	$0.01	68,217,998	4,976,747	13.71	$0.08
WECC	$317,118	670,710,000	$0.00	239,135,284	26,736,937	8.94	$0.00
U.S.	**$400,057,466**	**3,752,709,980**	**$0.11**	**1,333,214,923**	**124,563,540**	**10.70**	**$1.14**

Table 7-3: Average Annual Cost per Household in 2015 by NERC Region and Regulatory Option ($2013)[a]

NERC Region	Total Annual Compliance Cost (at 2015; $2013)	Total Electricity Sales (at 2014; MWh)	Compliance Cost per Unit of Sales ($2013/MWh)	Residential Electricity Sales (at 2015; MWh)	Number of Households (at 2015)	Residential Sales per Residential Consumer (MWh)	Compliance Cost per Household ($2013)
Option D							
ASCC	$0	6,288,931	$0.00	2,117,367	267,167	7.93	$0.00
FRCC	$1,312,331	210,529,236	$0.01	105,233,155	8,121,801	12.96	$0.08
HICC	$0	9,639,157	$0.00	2,739,298	419,612	6.53	$0.00
MRO	$28,672,431	208,620,000	$0.14	56,124,684	5,530,600	10.15	$1.39
NPCC	$1,006,148	260,550,000	$0.00	102,150,404	13,620,886	7.50	$0.03
RFC	$230,647,410	866,450,000	$0.27	337,291,906	33,594,289	10.04	$2.67
SERC	$196,526,405	1,009,880,000	$0.19	351,008,786	25,921,554	13.54	$2.64
SPP	$26,283,895	196,820,000	$0.13	69,196,041	5,373,947	12.88	$1.72
TRE	$1,730,340	313,222,656	$0.01	68,217,998	4,976,747	13.71	$0.08
WECC	$9,989,162	670,710,000	$0.01	239,135,284	26,736,937	8.94	$0.13
U.S.	**$496,168,123**	**3,752,709,980**	**$0.13**	**1,333,214,923**	**124,563,540**	**10.70**	**$1.42**
Option E							
ASCC	$0	6,288,931	$0.00	2,117,367	267,167	7.93	$0.00
FRCC	$1,312,331	210,529,236	$0.01	105,233,155	8,121,801	12.96	$0.08
HICC	$0	9,639,157	$0.00	2,739,298	419,612	6.53	$0.00
MRO	$32,580,617	208,620,000	$0.16	56,124,684	5,530,600	10.15	$1.58
NPCC	$1,477,964	260,550,000	$0.01	102,150,404	13,620,886	7.50	$0.04
RFC	$264,323,058	866,450,000	$0.31	337,291,906	33,594,289	10.04	$3.06
SERC	$208,867,320	1,009,880,000	$0.21	351,008,786	25,921,554	13.54	$2.80
SPP	$31,463,167	196,820,000	$0.16	69,196,041	5,373,947	12.88	$2.06
TRE	$3,888,177	313,222,656	$0.01	68,217,998	4,976,747	13.71	$0.17
WECC	$9,989,162	670,710,000	$0.01	239,135,284	26,736,937	8.94	$0.13
U.S.	**$553,901,796**	**3,752,709,980**	**$0.15**	**1,333,214,923**	**124,563,540**	**10.70**	**$1.58**

a. The rate impact analysis assumes full pass-through of all compliance costs to electricity consumers.
Sources: U.S. EPA Analysis, 2015; U.S. DOE, 2014a; U.S. DOE, 2012d.

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 final ELGs 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 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.

Further, the compliance costs used in this analysis reflect anticipated unit retirements, conversions, and repowerings announced through August 2014 scheduled to occur by 2023 and include projected conversions to dry systems in response to the final CCR rule. As discussed in *Chapter 3*, changes that may result from the CPP rule are based on EPA's understanding of those effects at the time the ELG analyses were conducted, based on the proposed CPP rule analysis. To the extent that unit retirements, conversions, and repowerings resulting from the final CPP rule differ from anticipated changes, total annualized compliance costs may differ from actual costs.

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. 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 will be able to pay for these electricity rate increases without experiencing economic hardship (*i.e.*, whether the increase is affordable). Relevant sub-questions include:

- What is the share of household income spent on energy across income groups in the baseline?
- What is the change in household income spent on energy across income groups as a result of the final ELGs?
- Does the post-compliance energy burden vary systematically across income groups?
- Does the post-compliance total household energy burden cross any "affordability challenge" threshold?

The analysis is meant to provide additional insight on the distribution of impacts among residential electricity consumers, and to help respond to comments EPA received on the proposed ELG concerning the impacts of the rule on utilities and cooperatives in service areas that include a relatively high proportion of low-income households. The analysis also furthers EPA's consideration of distributive impacts in accordance with Executive Order (EO) 13563 (*Improving Regulation and Regulatory Review*)[99] and Executive Order 12898 (*Federal Actions to Address Environmental Justice in Minority Populations and Low-income Populations*), covered in *Chapter 10* of this report.

Thus, the environmental justice (EJ) analysis described in *Section 10.2* addresses questions regarding the distribution of baseline environmental conditions and changes in those conditions across population categories resulting from a regulation, with specific focus on whether and the degree to which lower income and minority population categories are affected by the regulation. By contrast, here, EPA focuses on the distribution of the *costs* of the regulation in order to address concerns that energy prices comprise a larger share of low-income household budgets relative to high income households, and any increases in energy costs may result in a disproportionate burden. The distributional impacts depend on (1) how costs are passed through to customers of the goods and services whose prices may be affected by the regulation, (2) the profile of consumption of those goods and services across population groups, and (3) the baseline economic circumstances of, specifically, the population categories of concern – namely, lower income and minority population categories. In effect, the distributional analysis of compliance cost impacts looks at the economic impacts of a regulation from the perspective of households within the specified populations of concern, which may ultimately pay a share of those compliance costs.

[99] As stated in Section 1, paragraph c of EO 13563, "(c) In applying these principles, each agency is directed to use the best available techniques to quantify anticipated present and future benefits and costs as accurately as possible. Where appropriate and permitted by law, each agency may consider (and discuss qualitatively) values that are difficult or impossible to quantify, including equity, human dignity, fairness, *and distributive impacts*."

7.4.1 Analysis Approach and Data Inputs

As detailed below, the analysis seeks to understand the significance of the impacts in two ways:

- By assessing the *distributional* neutrality of electric rate increases. This first analysis looks at differences in the level of impact across household income ranges. The comparison considers three metrics: electricity price increase relative to after-tax income, electricity price increase relative to baseline energy expenditures, and electricity price increase relative to baseline housing expenditures.
- By assessing the *affordability* impact of electricity rate increases. This second analysis looks at two different indicators of affordability: increase in household electricity costs relative to gross income, and the increase in total household energy costs relative to gross income.

EPA used the same weighted pre-tax annualized compliance costs that are used for the assessment of electricity price effects discussed in *Section 7.3*, except that instead of summing these costs by NERC region, EPA summed them by state. This assumes that costs borne by a given facility are absorbed by consumers living in the state in which the facility operates. As for the previous analyses, EPA assumed that steam electric power plants will be able to pass 100 percent of their compliance costs onto electricity consumers through higher electricity rates. This provides a worst-case scenario of the impacts to households in states where the electricity market has been deregulated and where steam electric power plants may absorb some of the compliance costs.

To estimate an average electricity rate increase ($/MWh) in each state, EPA divided total state-level compliance costs by total state-level MWh of retail sales reported for 2012, based on data collected in the Form EIA-861 (U.S. DOE, 2013b).[100] This methodology assumes that all electricity consumer groups (*i.e.*, residential, industrial, commercial, and transportation) will see the same electricity rates increase ($/MWh).[101]

EPA then calculated the increase in annual household electricity costs by income range and state. EPA estimated an average annual increase in electricity costs accounting for electricity usage of the households as follows:

- <u>Estimate average annual electricity consumption by household income range and state.</u> EPA divided the mean electricity expenditures (in $) reported for households in a given household-income range by the average retail electricity price charged to residential consumers in each state (in $/MWh) to yield an estimate of electricity consumed (in MWh) annually per household, by income range. Household electricity expenditures were taken from the 2013 Consumer Expenditure Survey

[100] State-level summary of electricity sales is available online at http://www.eia.gov/electricity/sales_revenue_price/. 2012 was the latest year for which full-year data were available at the time EPA conducted the analysis.

[101] Actual electricity rate increases may differ across customer classes. Within a rate regulation framework that guarantees full cost recovery, assumed in this analysis, fixed and variable costs would be allocated among customer classes based on the contribution of each class to consumption during specific electricity production periods. As a result, the allocation of costs to the residential class could be higher or lower than those estimated in this analysis based on the assumption that costs would be passed on to consumers in the form of a flat-rate price increase per unit of power, to be distributed in proportion to the current electricity consumption profile. In addition, this analysis ignores heterogeneous impacts at the household level, which may be more important for utilities that use block-rate pricing or other price-discrimination rate structures, in which unit consumption prices vary by consumption level. The analysis also does not account for rate structures – *e.g.*, lifeline rates – which could moderate the impact of otherwise increased rates on lower income households.

(CES).[102] This survey only reports expenditures at the national level and for four regions (Northeast, Midwest, South, and West), so EPA assumed that expenditures in each state match the average values for the region (BLS, 2014).[103] The most recent electricity price data available from EIA are for 2012, so EPA adjusted these prices to 2013 using an index based on EIA's electricity price projections (U.S. DOE, 2013b and 2014b).

- Estimate increase in annual electricity costs for a household by household income range and state. EPA multiplied the state-level average electricity rate increase described above (in $/MWh) by the quantity of electricity estimated in the previous step (in MWh).

7.4.2 Distributional Affordability Impact of Electricity Rate Increases on Households

EPA assessed the impact of Steam Electric ELG on households with various income levels in two steps, described below.

EPA first assessed whether the impact of the Steam Electric ELG on an annual household electricity bill is distributionally neutral: (1) relative to household income, (2) relative to baseline energy expenditures, and (3) relative to baseline housing expenditures. For the first metric, EPA calculated the increase in annual household electricity costs as a percentage of the mean annual after-tax household income reported for 2013 in CES by household-income range and state. For the second and third metrics, EPA calculated the percentage value of the increased electricity expenditures relative to 2013 household expenditures on energy and housing, respectively, by household-income range. EPA then assessed whether each ratio is consistently greater for lower-income households compared to higher-income households.

The CES data show negative mean after-tax income for the lowest income range ($0 to $5,000) in the Northeast, Midwest, and West regions (*Table 7-4*). The Bureau of Labor Statistics (BLS) offers several possible reasons why incomes may be negative and/or expenditures exceed income for the lower income groups. For example: "Consumer units whose members experience a spell of unemployment may draw on their savings to maintain their expenditures. Self-employed consumers may experience business losses that result in low or even negative incomes, but are able to maintain their expenditures by borrowing or relying on savings. Students may get by on loans while they are in school, and retirees may rely on savings and investments." Some researchers question the reliability of incomes reported in at the low end of the range, particularly for categories where expenditures exceed income and some researchers address this issue by recalculating income statistics ignoring negative incomes. EPA was not able to use this approach for this analysis as it would require more detailed data than are readily available from BLS. Instead, EPA adjusted household incomes in each income range by subtracting the contribution from self-employment,[104]

[102] The Bureau of Labor Statistics notes that CES data are commonly used to study the impact of policy changes on the welfare of different socioeconomic groups. For more information on CES, see http://www.bls.gov/cex/pumdhome.htm.

[103] This assumption ignores income disparity within the regions and may contribute to over or understating the impacts. For example, Maine has a much lower average income than its region, but no costs are allocated to Maine residents from Steam Electric plants. Similarly, the regions may mask potentially significant differences in electricity consumption need for heating and cooling, and also differences in the underlying price of electricity due to differences in energy input, further contributing to over/understating of impacts calculated for households within individual states.

[104] Self-employment income appears to be a significant contributor to overall negative income reported for households in the lowest income range. For example, in the Midwest, mean self-employment income for households in the "Less than $5,000" category is -$4,319, as compared to mean wages of $1,507, Social Security and retirement income of $743, public assistance, supplemental security income, and food stamps income of

recognizing that this adjustment is necessarily rough and imprecise since CES only reports mean values for income sources and taxes and adding or subtracting means is not the same as calculating a mean from individually adjusted observations. Nevertheless, EPA determined that the adjustment provides a reasonable approximation of income for this analysis in order to provide meaningful metrics for assessing distributional affordability impacts for these household-income ranges. The adjusted after-tax income values are included in *Table 7-4* below. EPA similarly calculated adjusted pre-tax income by subtracting mean self-employment income from mean gross income. EPA calculated income-based affordability metrics using both the reported after-tax income and the adjusted after-tax income.

Table 7-4: Number of Households and After-Tax Income, by Region and Household Income Range

Item	All consumer units	Less than $5,000	$5,000 to $9,999	$10,000 to $14,999	$15,000 to $19,999	$20,000 to $29,999	$30,000 to $39,999	$40,000 to $49,999	$50,000 to $69,999	$70,000 and more
(1) Number of households (Thousand)										
Northeast	22,614	960	833	1,512	1,299	2,382	2,066	1,924	3,220	8,418
Midwest	27,744	1,176	1,312	1,777	1,772	3,022	3,119	2,406	4,227	8,933
South	46,625	2,161	2,175	3,484	3,321	5,897	5,307	4,298	6,473	13,510
West	28,059	993	1,109	1,649	1,742	3,332	2,786	2,466	4,009	9,973
U.S. Total	***125,670***	***5,675***	***5,686***	***8,751***	***8,261***	***14,750***	***13,031***	***11,179***	***17,887***	***40,451***
(2) After-tax income										
Northeast	$65,585	-$2,608	$8,107	$13,069	$18,051	$25,293	$34,384	$42,890	$56,036	$123,722
Midwest	$58,962	-$1,225	$8,089	$13,211	$17,926	$25,344	$34,331	$43,260	$56,072	$117,165
South	$55,566	$831	$8,420	$13,057	$17,977	$25,414	$34,435	$43,787	$56,818	$116,721
West	$63,196	-$1,336	$8,335	$13,060	$18,072	$25,286	$34,782	$43,335	$56,630	$120,049
U.S. Total	**$56,352**	**$565**	**$8,339**	**$13,352**	**$18,203**	**$25,631**	**$34,196**	**$42,571**	**$54,713**	**$110,894**
(3) Adjusted after-tax income, without self-employment income										
Northeast	$63,133	[a] $5,010	$7,978	$13,105	$18,113	$24,920	$33,646	$42,118	$54,520	$117,303
Midwest	$55,696	$3,093	$8,004	$13,117	$17,675	$24,925	$33,417	$41,909	$53,675	$108,495
South	$52,768	$3,500	$8,352	$12,911	$17,597	$25,022	$33,499	$42,644	$54,580	$108,758
West	$59,253	$4,371	$8,360	$12,928	$17,426	$24,682	$33,517	$41,278	$54,465	$110,455
U.S. Total	**$53,079**	**$3,403**	**$8,203**	**$13,201**	**$17,750**	**$25,166**	**$33,213**	**$41,310**	**$52,393**	**$102,331**

[a] Adjusted income exceeds the upper bound of the range.

Source: U.S. EPA Analysis, 2015; BLS, 2014.

As the second step, EPA assessed the ability of households to pay for these cost increases without experiencing economic hardship.

- *Comparing Increase in Household Electricity Costs to Gross Income*. EPA evaluated the increase in electricity costs, expressed as percent of gross household income (pre-tax) calculated above, against

$501, and other income of $555. Subtracting mean self-employment income from mean after-tax income results in adjusted income of $3,093 as compared to -$1,225 (see *Table 7-4*).

two thresholds, 1 percent and 2 percent, per EPA's guidance.[105] If this increase in electricity costs is less than 1 percent of annual household income, EPA assessed the ELGs as not imposing a substantial economic hardship on households in a given income range and state. If that increase exceeds the 2-percent threshold, then EPA assessed the ELGs as potentially placing a significant economic burden on households in given income group and state. If the increase in electricity costs is between 1 and 2 percent of annual household pre-tax income, EPA assessed the ELGs as having an indeterminate impact. EPA also estimated the share of total state households for which the estimated increase in household electricity cost would pose a significant economic burden, *i.e.*, exceeds the 2-percent threshold.

- *Comparing Increase in Total Household Energy Costs to Gross Income*. For this analysis, EPA evaluated total annual household energy costs as a percentage of household pre-tax income, before and after the increase in electricity costs from the final rule, relative to a 6-percent affordability threshold. EPA uses this threshold to determine the energy affordability gap, defined as the difference between affordable and actual home energy bills, where home energy bills are considered to be unaffordable if they represent more than 6 percent of pre-tax annual household income.[106] The energy affordability gap analysis has been used to examine the burden of home energy bills in various states.[107] For this calculation, EPA used pre-tax income and home energy expenditures, which include spending on electricity, natural gas, fuel oil, and other fuels, as reported in CES for 2013 by household-income range and region. According to the CES data, in 2013, electricity expenditures on average represented 73 percent of total household energy expenditures and total household energy expenditures represented about 3 percent of pre-tax income.[108] EPA used the increase in electricity costs calculated in the previous step, and assumed that other energy expenditures are unaffected by the ELGs. EPA first considered the baseline household energy burden, by household-income range and state, to determine which households are already above the threshold for significant affordability challenges. EPA then assessed how compliance costs will affect these households and whether compliance costs will cause other households to exceed the threshold. As part of the analysis, EPA also estimated the share of total state population of households for which the estimated increase in household electricity cost would present a significant affordability challenge, *i.e.*, annual household energy costs exceeding the 6-percent threshold.

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105 EPA developed these affordability thresholds to indicate when a regulation may cause substantial and widespread economic distress in a community. See EPA's Guidelines for Preparing Economic Analyses (U.S. EPA, 2010c).

Note that according to U.S. BLS, average baseline electricity costs already exceed 2 percent of pre-tax income. Average expenditures on "water and other public services", on the other hand, make up less than 1 percent of pre-tax income. For details, see *Table 1101. Quintiles of income before taxes: Annual expenditure means, shares, standard errors, and coefficient of variation, Consumer Expenditure Survey, 2012* available online at http://www.bls.gov/cex/2012/combined/quintile.pdf.

106 The 6-percent threshold is based on the assumption that utility costs should not exceed 20 percent of shelter costs and that total shelter costs, which include rent/mortgage and all utilities, should not exceed 30 percent of income, a well-established threshold for housing burden (Schwartz and Wilson, 2008). For more information, see Fisher, Sheehan & Colton (2011).

107 For example, see Fisher, Sheehan & Colton (2011).

108 For details, see *Table 1101. Quintiles of income before taxes: Annual expenditure means, shares, standard errors, and coefficient of variation, Consumer Expenditure Survey, 2012* available online at http://www.bls.gov/cex/2012/combined/quintile.pdf.

7.4.3 Key Findings

The following sections describe the key findings for the final BAT/PSES (Option D).

Assessing Distributional Neutrality of Electric Rate Increases

State-level values reflect differences in ELG compliance costs, electricity consumption, household income, and energy and housing expenditure across the states. For each of the three metrics considered (electricity price increase relative to: after-tax income, baseline energy expenditures, and baseline housing expenditures) EPA found that the impact is highest for the lowest income range and declines as income rises. *Table 7-5* shows the distribution for the overall United States and for the five states with the largest post-compliance increases in household annual electricity expenditures. The table summarizes the impacts relative to the unadjusted incomes, adjusted income, energy expenditures, and housing expenditures. Note that impacts relative to energy and housing expenditures generally reflect the fraction of income going to energy and housing in for households in different income ranges.

Overall, the results (particularly when considering impacts relative to income) show that the *final rule is not distributionally neutral* and that impacts are most significant, in relative term, for households in the lower income categories, *i.e.*, relative impacts are not uniform across the income ranges. The largest impact on any household group occurs in West Virginia where the increase in electricity price represents 0.42 percent of the adjusted household income of households in the "Less than $5,000" income range, whereas the relative impact for households in the "$70,000 or more" range is approximately 0.02 percent. The results for the United States as a whole show impacts that are more uniform across the income ranges, than those for the top 5 states. Other states fall in between these results along the gradient of neutral to skewed distribution.

Table 7-5: Electricity Price Increase for Option D Relative to: (1) After-tax Income, (2) Baseline Energy Expenditure and (3) Baseline Housing Expenditure, by Household Income Range for Top 5 States with the Highest Post-compliance Increases in Household Annual Electricity Expenditures

Item	All consumer units	Less than $5,000	$5,000 to $9,999	$10,000 to $14,999	$15,000 to $19,999	$20,000 to $29,999	$30,000 to $39,999	$40,000 to $49,999	$50,000 to $69,999	$70,000 and more
(1) Electricity price increase relative to after-tax income (unadjusted)										
Indiana	0.01%	[a]	0.04%	0.03%	0.03%	0.02%	0.02%	0.01%	0.01%	0.01%
Kentucky	0.02%	0.81%	0.08%	0.05%	0.04%	0.03%	0.03%	0.02%	0.02%	0.01%
Missouri	0.01%	[a]	0.04%	0.03%	0.02%	0.02%	0.02%	0.01%	0.01%	0.01%
North Dakota	0.01%	[a]	0.04%	0.03%	0.03%	0.02%	0.02%	0.01%	0.01%	0.01%
West Virginia	0.04%	1.76%	0.17%	0.12%	0.09%	0.07%	0.06%	0.05%	0.04%	0.02%
U.S. Total	0.00%	**0.17%**	0.01%	0.01%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%
(2) Electricity price increase relative to after-tax income, adjusted for self-employment										
Indiana	0.01%	0.10%	0.04%	0.03%	0.03%	0.02%	0.02%	0.01%	0.01%	0.01%
Kentucky	0.02%	0.19%	0.08%	0.05%	0.04%	0.03%	0.03%	0.02%	0.02%	0.01%
Missouri	0.01%	0.10%	0.04%	0.03%	0.03%	0.02%	0.02%	0.01%	0.01%	0.01%
North Dakota	0.01%	0.10%	0.04%	0.03%	0.03%	0.02%	0.02%	0.01%	0.01%	0.01%
West Virginia	0.04%	0.42%	0.17%	0.12%	0.09%	0.07%	0.06%	0.05%	0.04%	0.02%
U.S. Total	**0.00%**	**0.03%**	**0.01%**	**0.01%**	**0.01%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**
(3) Electricity price increase relative to baseline energy expenditure										
Indiana	0.29%	0.31%	0.31%	0.30%	0.30%	0.30%	0.30%	0.29%	0.29%	0.29%
Kentucky	0.48%	0.50%	0.51%	0.50%	0.48%	0.49%	0.50%	0.50%	0.50%	0.46%

Table 7-5: Electricity Price Increase for Option D Relative to: (1) After-tax Income, (2) Baseline Energy Expenditure and (3) Baseline Housing Expenditure, by Household Income Range for Top 5 States with the Highest Post-compliance Increases in Household Annual Electricity Expenditures

Item	All consumer units	Less than $5,000	$5,000 to $9,999	$10,000 to $14,999	$15,000 to $19,999	$20,000 to $29,999	$30,000 to $39,999	$40,000 to $49,999	$50,000 to $69,999	$70,000 and more
Missouri	0.29%	0.31%	0.31%	0.30%	0.29%	0.30%	0.29%	0.29%	0.29%	0.28%
North Dakota	0.31%	0.33%	0.33%	0.32%	0.31%	0.31%	0.31%	0.30%	0.31%	0.30%
West Virginia	1.05%	1.08%	1.10%	1.09%	1.04%	1.06%	1.08%	1.08%	1.08%	1.00%
U.S. Total	**0.07%**	**0.08%**	**0.08%**	**0.08%**	**0.07%**	**0.07%**	**0.07%**	**0.07%**	**0.07%**	**0.07%**
(4) Electricity price increase relative to baseline housing expenditure										
Indiana	0.04%	0.04%	0.04%	0.05%	0.05%	0.05%	0.04%	0.04%	0.04%	0.03%
Kentucky	0.06%	0.08%	0.09%	0.09%	0.08%	0.08%	0.07%	0.07%	0.06%	0.05%
Missouri	0.04%	0.04%	0.04%	0.05%	0.05%	0.04%	0.04%	0.04%	0.04%	0.03%
North Dakota	0.04%	0.04%	0.05%	0.05%	0.05%	0.05%	0.05%	0.04%	0.04%	0.03%
West Virginia	0.13%	0.16%	0.20%	0.20%	0.18%	0.17%	0.16%	0.15%	0.14%	0.10%
U.S. Total	**0.01%**	**0.01%**	**0.01%**	**0.01%**	**0.01%**	**0.01%**	**0.01%**	**0.01%**	**0.01%**	**0.01%**

[a] Average after-tax income is negative for this income group. The Bureau of Labor Statistics offers several possible reasons why income may be negative and/or expenditures may exceed income for the lower income groups. For example: "Consumer units whose members experience a spell of unemployment may draw on their savings to maintain their expenditures. Self-employed consumers may experience business losses that result in low or even negative incomes, but are able to maintain their expenditures by borrowing or relying on savings. Students may get by on loans while they are in school, and retirees may rely on savings and investments." (http://www.bls.gov/cex/faq.htm#q21)

Source: U.S. EPA Analysis, 2015.

Assessing Affordability Impact of Electricity Rate Increases

EPA assesses the impact of electricity rate increases on affordability in two ways.

For the first analysis, EPA compared the post-compliance increase in electricity costs to pre-tax household income, for state and household-income ranges. When using the adjusted incomes across income groups, EPA found that none of household groups exceed the 1 percent threshold value (or the 2 percent threshold value). Looking at reported income groups and setting aside groups with negative incomes, only one household-income range in one state (households with pre-tax income less than $5,000 in West Virginia) exceeds the 1 percent threshold value and no household-income range in any state exceeds the 2 percent threshold value (see *Table 7-5*).

The results of the first analysis indicate that the incremental economic burden of the final rule on households is small.

For the second analysis, EPA compared the increase in total household energy costs to gross income. A review of the baseline energy burden, defined as the ratio of energy expenditures relative to gross (pre-tax) income, indicates that households in the lowest four income ranges (less than $5,000; $5,000 to $9,999; $10,000 to $14,999; $15,000 to $19,999) have baseline burdens that exceed the 6 percent threshold in all states and the District of Columbia (*Table 7-6*). For the next lowest income range ($20,000 to $29,999), 39 states have households with baseline energy burdens exceeding the threshold. Households in all remaining four income ranges ($30,000 or higher) have baseline energy burden below the threshold in all areas. This observation holds whether one uses household incomes as reported in CES, or adjusted household incomes. When considering the effect of the final ELGs, by state and income range, EPA found that the post-compliance energy burden increases further for state-household groups that were already above the threshold in the baseline (35 and 31 states, depending on the income level), but the additional electricity costs due to the final rule do not push any *additional* state-household groups above the 6 percent threshold. The increase in burden for states-household groups already above the 6 percent energy burden threshold is very small. The maximum relative change occurs in West Virginia where households in the "Less than $5,000" range see their energy burden increase from 38.8 percent to 39.2 percent (0.4 percent change) (see *Table 7-7*).

The results of the second analysis indicate that the final rule will increase energy costs for households with already high baseline energy burdens—absent any measure to mitigate the increase—but that increase is, again, small.

Table 7-6: Number of Areas with Households Exceeding a 6-Percent Energy Burden Threshold, by Household Income Range

Item	Less than $5,000	$5,000 to $9,999	$10,000 to $14,999	$15,000 to $19,999	$20,000 to $29,999	$30,000 to $39,999	$40,000 to $49,999	$50,000 to $69,999	$70,000 and more
Number of states (and D.C.) exceeding threshold for energy burden in baseline	51	51	51	51	39	0	0	0	0
Number of states (and D.C.) with high baseline burden and increased electricity rates under Option D	35	35	35	35	31	0	0	0	0
Change in the number of states (and D.C.) that exceed the threshold for energy burden under Option D	0	0	0	0	0	0	0	0	0

Source: U.S. EPA Analysis, 2015.

Table 7-7: Baseline and post-compliance energy burden (under Option D) by state and by household income range (states with non-zero ELG costs)

State	Period	All consumer units	Less than $5,000	$5,000 to $9,999	$10,000 to $14,999	$15,000 to $19,999	$20,000 to $29,999	$30,000 to $39,999	$40,000 to $49,999	$50,000 to $69,999	$70,000 and more
Alabama	Baseline	3.4%	38.8%	15.9%	11.1%	9.5%	7.1%	5.2%	4.4%	3.5%	2.0%
	Post-Compliance	3.4%	38.8%	15.9%	11.1%	9.5%	7.1%	5.3%	4.4%	3.5%	2.0%
Arkansas	Baseline	2.5%	22.4%	11.9%	7.7%	6.3%	5.1%	4.1%	3.5%	2.8%	1.8%
	Post-Compliance	2.5%	22.4%	11.9%	7.7%	6.3%	5.1%	4.1%	3.5%	2.8%	1.8%
Colorado	Baseline	2.5%	22.4%	11.9%	7.7%	6.3%	5.1%	4.1%	3.5%	2.8%	1.8%
	Post-Compliance	2.5%	22.4%	11.9%	7.7%	6.3%	5.1%	4.1%	3.5%	2.8%	1.8%
Connecticut	Baseline	3.4%	38.8%	15.9%	11.1%	9.5%	7.1%	5.2%	4.4%	3.5%	2.0%
	Post-Compliance	3.4%	38.8%	15.9%	11.1%	9.5%	7.1%	5.2%	4.4%	3.5%	2.0%
Florida	Baseline	2.5%	22.4%	11.9%	7.7%	6.3%	5.1%	4.1%	3.5%	2.8%	1.8%
	Post-Compliance	2.5%	22.4%	11.9%	7.7%	6.3%	5.1%	4.1%	3.5%	2.8%	1.8%
Georgia	Baseline	2.5%	22.4%	11.9%	7.7%	6.3%	5.1%	4.1%	3.5%	2.8%	1.8%
	Post-Compliance	2.5%	22.4%	11.9%	7.7%	6.3%	5.1%	4.1%	3.5%	2.8%	1.8%
Illinois	Baseline	3.3%	25.9%	13.3%	10.4%	8.6%	7.6%	5.9%	5.1%	4.1%	2.3%
	Post-Compliance	3.3%	25.9%	13.3%	10.4%	8.6%	7.6%	5.9%	5.1%	4.1%	2.3%
Indiana	Baseline	3.3%	25.9%	13.3%	10.4%	8.6%	7.6%	5.9%	5.1%	4.1%	2.3%
	Post-Compliance	3.3%	25.9%	13.3%	10.4%	8.6%	7.6%	5.9%	5.1%	4.1%	2.3%
Iowa	Baseline	3.4%	38.8%	15.9%	11.1%	9.5%	7.1%	5.2%	4.4%	3.5%	2.0%
	Post-Compliance	3.4%	38.8%	15.9%	11.1%	9.5%	7.1%	5.2%	4.4%	3.5%	2.0%
Kansas	Baseline	3.4%	38.8%	15.9%	11.1%	9.5%	7.1%	5.2%	4.4%	3.5%	2.0%
	Post-Compliance	3.4%	38.8%	15.9%	11.1%	9.5%	7.1%	5.2%	4.4%	3.5%	2.0%

Table 7-7: Baseline and post-compliance energy burden (under Option D) by state and by household income range (states with non-zero ELG costs)

State	Period	All consumer units	Less than $5,000	$5,000 to $9,999	$10,000 to $14,999	$15,000 to $19,999	$20,000 to $29,999	$30,000 to $39,999	$40,000 to $49,999	$50,000 to $69,999	$70,000 and more
Kentucky	Baseline	3.4%	38.8%	15.9%	11.1%	9.5%	7.1%	5.2%	4.4%	3.5%	2.0%
	Post-Compliance	3.4%	38.8%	15.9%	11.1%	9.5%	7.1%	5.3%	4.4%	3.5%	2.0%
Louisiana	Baseline	2.5%	22.4%	11.9%	7.7%	6.3%	5.1%	4.1%	3.5%	2.8%	1.8%
	Post-Compliance	2.5%	22.4%	11.9%	7.7%	6.3%	5.1%	4.1%	3.5%	2.8%	1.8%
Maryland	Baseline	2.5%	22.4%	11.9%	7.7%	6.3%	5.1%	4.1%	3.5%	2.8%	1.8%
	Post-Compliance	2.5%	22.4%	11.9%	7.7%	6.3%	5.1%	4.1%	3.5%	2.8%	1.8%
Massachusetts	Baseline	3.1%	30.1%	13.6%	9.6%	8.8%	6.6%	5.3%	4.2%	3.6%	2.0%
	Post-Compliance	3.1%	30.2%	13.6%	9.6%	8.8%	6.6%	5.3%	4.2%	3.6%	2.0%
Michigan	Baseline	3.1%	30.1%	13.6%	9.6%	8.8%	6.6%	5.3%	4.2%	3.6%	2.0%
	Post-Compliance	3.1%	30.2%	13.6%	9.6%	8.8%	6.6%	5.3%	4.3%	3.7%	2.0%
Minnesota	Baseline	3.1%	30.1%	13.6%	9.6%	8.8%	6.6%	5.3%	4.2%	3.6%	2.0%
	Post-Compliance	3.1%	30.2%	13.6%	9.6%	8.8%	6.6%	5.3%	4.3%	3.7%	2.0%
Mississippi	Baseline	3.1%	30.1%	13.6%	9.6%	8.8%	6.6%	5.3%	4.2%	3.6%	2.0%
	Post-Compliance	3.1%	30.2%	13.6%	9.6%	8.8%	6.6%	5.3%	4.3%	3.7%	2.0%
Missouri	Baseline	3.4%	38.8%	15.9%	11.1%	9.5%	7.1%	5.2%	4.4%	3.5%	2.0%
	Post-Compliance	3.4%	39.0%	15.9%	11.1%	9.5%	7.1%	5.3%	4.4%	3.5%	2.1%
Montana	Baseline	3.4%	38.8%	15.9%	11.1%	9.5%	7.1%	5.2%	4.4%	3.5%	2.0%
	Post-Compliance	3.4%	38.8%	15.9%	11.1%	9.5%	7.1%	5.2%	4.4%	3.5%	2.0%
Nebraska	Baseline	3.3%	25.9%	13.3%	10.4%	8.6%	7.6%	5.9%	5.1%	4.1%	2.3%
	Post-Compliance	3.3%	25.9%	13.3%	10.4%	8.6%	7.6%	5.9%	5.1%	4.1%	2.3%
New Hampshire	Baseline	3.4%	38.8%	15.9%	11.1%	9.5%	7.1%	5.2%	4.4%	3.5%	2.0%
	Post-Compliance	3.4%	38.8%	15.9%	11.1%	9.5%	7.1%	5.3%	4.4%	3.5%	2.0%
New Jersey	Baseline	3.3%	25.9%	13.3%	10.4%	8.6%	7.6%	5.9%	5.1%	4.1%	2.3%
	Post-Compliance	3.3%	25.9%	13.3%	10.4%	8.6%	7.6%	5.9%	5.1%	4.1%	2.3%
New York	Baseline	3.1%	30.1%	13.6%	9.6%	8.8%	6.6%	5.3%	4.2%	3.6%	2.0%
	Post-Compliance	3.1%	30.2%	13.6%	9.6%	8.8%	6.6%	5.3%	4.3%	3.7%	2.0%
North Carolina	Baseline	3.1%	30.1%	13.6%	9.6%	8.8%	6.6%	5.3%	4.2%	3.6%	2.0%
	Post-Compliance	3.1%	30.1%	13.6%	9.6%	8.8%	6.6%	5.3%	4.2%	3.6%	2.0%
North Dakota	Baseline	3.4%	38.8%	15.9%	11.1%	9.5%	7.1%	5.2%	4.4%	3.5%	2.0%
	Post-Compliance	3.4%	38.8%	15.9%	11.1%	9.5%	7.1%	5.2%	4.4%	3.5%	2.0%
Ohio	Baseline	3.1%	30.1%	13.6%	9.6%	8.8%	6.6%	5.3%	4.2%	3.6%	2.0%
	Post-Compliance	3.1%	30.2%	13.6%	9.6%	8.8%	6.6%	5.3%	4.3%	3.7%	2.0%
Oklahoma	Baseline	2.5%	22.4%	11.9%	7.7%	6.3%	5.1%	4.1%	3.5%	2.8%	1.8%
	Post-Compliance	2.5%	22.4%	11.9%	7.7%	6.3%	5.1%	4.1%	3.5%	2.8%	1.8%
Pennsylvania	Baseline	3.1%	30.1%	13.6%	9.6%	8.8%	6.6%	5.3%	4.2%	3.6%	2.0%
	Post-Compliance	3.1%	30.2%	13.6%	9.6%	8.8%	6.6%	5.3%	4.3%	3.7%	2.0%
South Carolina	Baseline	2.5%	22.4%	11.9%	7.7%	6.3%	5.1%	4.1%	3.5%	2.8%	1.8%
	Post-Compliance	2.5%	22.4%	11.9%	7.7%	6.3%	5.1%	4.1%	3.5%	2.8%	1.8%
Tennessee	Baseline	3.3%	25.9%	13.3%	10.4%	8.6%	7.6%	5.9%	5.1%	4.1%	2.3%
	Post-Compliance	3.3%	25.9%	13.3%	10.4%	8.6%	7.6%	5.9%	5.1%	4.1%	2.3%
Texas	Baseline	3.3%	25.9%	13.3%	10.4%	8.6%	7.6%	5.9%	5.1%	4.1%	2.3%
	Post-Compliance	3.3%	25.9%	13.3%	10.4%	8.6%	7.6%	5.9%	5.1%	4.1%	2.3%
Virginia	Baseline	2.5%	22.4%	11.9%	7.7%	6.3%	5.1%	4.1%	3.5%	2.8%	1.8%
	Post-Compliance	2.5%	22.4%	11.9%	7.7%	6.3%	5.1%	4.1%	3.5%	2.8%	1.8%
Washington	Baseline	3.3%	25.9%	13.3%	10.4%	8.6%	7.6%	5.9%	5.1%	4.1%	2.3%
	Post-Compliance	3.3%	25.9%	13.3%	10.4%	8.6%	7.6%	5.9%	5.1%	4.1%	2.3%
West Virginia	Baseline	3.4%	38.8%	15.9%	11.1%	9.5%	7.1%	5.2%	4.4%	3.5%	2.0%
	Post-Compliance	3.4%	38.8%	15.9%	11.1%	9.5%	7.1%	5.3%	4.4%	3.5%	2.0%
Wisconsin	Baseline	3.1%	30.1%	13.6%	9.6%	8.8%	6.6%	5.3%	4.2%	3.6%	2.0%
	Post-Compliance	3.1%	30.2%	13.6%	9.6%	8.8%	6.6%	5.3%	4.3%	3.7%	2.0%
Wyoming	Baseline	3.1%	30.1%	13.6%	9.6%	8.8%	6.6%	5.3%	4.2%	3.6%	2.0%
	Post-Compliance	3.1%	30.2%	13.6%	9.6%	8.8%	6.6%	5.3%	4.2%	3.6%	2.0%

Table 7-7: Baseline and post-compliance energy burden (under Option D) by state and by household income range (states with non-zero ELG costs)

State	Period	All consumer units	Less than $5,000	$5,000 to $9,999	$10,000 to $14,999	$15,000 to $19,999	$20,000 to $29,999	$30,000 to $39,999	$40,000 to $49,999	$50,000 to $69,999	$70,000 and more
U.S. Total	**Baseline**	**3.4%**	**38.8%**	**15.9%**	**11.1%**	**9.5%**	**7.1%**	**5.2%**	**4.4%**	**3.5%**	**2.0%**
	Post-Compliance	**3.4%**	**38.8%**	**15.9%**	**11.1%**	**9.5%**	**7.1%**	**5.2%**	**4.4%**	**3.5%**	**2.0%**

Source: U.S. EPA Analysis, 2015.

These two analyses suggest that the incremental economic burden of the final rule 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 low income households to a greater extent than higher income households, the small impacts may be further moderated by existing pricing structures (see next section).

7.4.4 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 final ELGs on households. For this screening-level analysis, EPA applied the 100 percent pass-through assumption to all states. Results based on the 100 percent pass-through assumptions suggest very little impacts, reducing the usefulness of conducting alternate, more detailed analyses.

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 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. In addition, this analysis assumes that any increase in electricity rates affects all users equally based on their consumption. This does not account for block-rate pricing or other price-discrimination rate structures, in which unit consumption prices vary by consumption level, or for other rate structures – *e.g.*, lifeline rates – which could moderate the impact of otherwise increased rates on lower income households.

8 Assessment of Potential Impact of the Final ELGs 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,[109] to analyze alternatives that minimize those impacts, and to make their analyses available for public comments. The Act 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, expected 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, EPA assessed whether the final ELGs would have "a significant impact on a substantial number of small entities" (SISNOSE). 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) (2014) size criteria.
- Assessing the 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. EPA used threshold compliance costs of 1 percent or 3 percent of entity-level revenue to categorize the degree of *significance* of the economic impacts on small entities.
- Assessing whether those small entities incurring potentially significant impacts represent a substantial number of small entities. 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.

EPA performed this assessment for the five regulatory options defined in *Chapter 1: Introduction* and discussed throughout this document. This chapter describes the analytic approach (*Section 8.1*), summarizes the findings of EPA's RFA assessment (*Section 8.2*), and reviews uncertainties and limitations in the analysis (*Section 8.3*). The Chapter also discusses how regulatory options developed by EPA serve to mitigate the impact of the final ELGs on small entities (*Section 8.4*).

[109] 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.

8.1 Analysis Approach and Data Inputs

EPA used the following methodology and assumptions to conduct the RFA analysis in support of the final ELGs.

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*), 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)[110] in at least one surveyed steam electric power plant. As was done for the entity-level cost-to-revenue analysis, EPA identified the majority owner for each surveyed plant using the 2010 Questionnaire for the Steam Electric Power Generating Effluent Guidelines (industry survey; U.S. EPA, 2010a), 2012 databases published by the Department of Energy's Energy Information Administration (EIA) (U.S. DOE, 2012c; U.S DOE, 2012d), and corporate and financial websites.

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

EPA identified the size of each parent entity identified in the previous step using the Small Business Administration (SBA) size threshold guidelines in effect as of July 14, 2014. The criteria for entity size determination vary by the organization/operation category of the parent entity, as follows:

- Privately owned (non-government) entities (see *Table 8-1*)
  - 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).
  - 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. [111]

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

NAICS Code	NAICS Description	SBA Size Standard[b]
211111	Crude Petroleum and Natural Gas Extraction	500 Employees
212111	Bituminous Coal and Lignite Surface Mining	500 Employees
213112	Support Activities for Oil and Gas Operations	$37.7 million in revenue
221111	Hydroelectric Power Generation	500 Employees
221112	Fossil Fuel Electric Power Generation	750 Employees
221113	Nuclear Electric Power Generation	750 Employees
221114	Solar Electric Power Generation	250 Employees
221115	Wind Electric Power Generation	250 Employees
221116	Geothermal Electric Power Generation	250 Employees

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

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

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

NAICS Code	NAICS Description	SBA Size Standard[b]
221117	Biomass Electric Power Generation	250 Employees
221118	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	500 Employees
221310	Water Supply and Irrigation Systems	$26.9 million in revenue
221330	Steam and Air-Conditioning Supply	$14.7 million in revenue
237130	Power and Communication Line and Related Structures Construction	$35.8 million in revenue
324110	Petroleum Refineries	1,500 Employees
332410	Power Boiler and Heat Exchanger Manufacturing	500 Employees
333611	Turbine and Turbine Generator Set Unit Manufacturing	1,000 Employees
423510	Metal Service Centers and Other Metal Merchant Wholesalers	100 Employees
486110	Pipeline Transportation of Crude Oil	1,500 Employees
522110	Commercial Banking	$539 million in assets
523110	Investment Banking and Securities Dealing	$37.7 million in revenue
523910	Miscellaneous Intermediation	$37.7 million in revenue
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
525910	Open-End Investment Funds	$31.8 million in revenue
541614	Process, Physical Distribution and Logistics Consulting Services	$15 million in revenue
541690	Other Scientific and Technical Consulting Services	$15 million in revenue
551111	Offices of Bank Holding Companies	$20.1 million in revenue
551112	Offices of Other Holding Companies	$20.1 million in revenue
562219	Other Nonhazardous Waste Treatment and Disposal	$37.7 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 July 14, 2014). Revenue and asset-based size standards adjusted to 2013 dollar year.

Source: SBA, 2014

- 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
- 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*).

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

- **Employment**: EPA used entity-level employment values from the industry survey, if those values were reported. For entities with values reported for more than one survey year (*i.e.*, 2007, 2008, and/or 2009), EPA used the average of reported values. For entities with values reported for only one survey year, EPA used the reported value. For entities with no employment values reported in the industry survey, EPA used employment values from corporate/financial websites.
- **Revenue**: EPA used entity-level revenue values from the industry survey, if those values were reported. For entities with values reported for more than one survey year (*i.e.*, 2007, 2008, and/or 2009), EPA used the average of reported values. For entities with values reported for only one survey year, EPA used the reported value. For entities with no revenue values reported in the industry survey, EPA used revenue values from corporate/financial websites, if those values were available; to be consistent with the data collected through the industry survey, EPA tried to obtain revenue for at least one of the three survey years (*i.e.*, 2007, 2008, and/or 2009) and used the average of reported values. If revenue values were not reported on corporate/financial websites, the Agency used the 2007-2009 average revenue values from the EIA-861 database (U.S. DOE, 2009b). EPA restated entity revenue values in dollar year 2010 using the Gross Domestic Product (GDP deflator index published by the U.S. Bureau of Economic Analysis (BEA) (2014).
- **Population**: Population data for municipalities and other non-state political subdivisions were obtained from the U.S. Census Bureau (estimated population for 2013) (U.S. DOC, 2014).

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*, EPA estimated the number of small entities owning steam electric power plants as a range, based on alternative assumptions about the possible ownership of potentially regulated electric power plants by small entities. EPA analyzed two cases based on the sample weights developed from the industry survey. These cases 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.

- *Case 1: Lower bound estimate of number of entities owning steam electric power plants; upper bound estimate of total compliance costs that an entity may incur.* For this case, EPA assumed that any entity owning a sample plant(s) owns the known sample plant(s) and all of the sample weight associated with the sample plant(s). This case minimizes the count of affected entities, while tending to maximize the potential cost burden to any single entity.
- *Case 2: Upper bound estimate of number of entities owning steam electric power plants; lower bound estimate of total compliance costs that an entity may incu*r. For this case, EPA assumed (1) that an entity owns only the sample plant(s) that it is known to own from the sample analysis and (2) that this pattern of ownership, observed for sampled plants and their owning entities, extends over the plant population represented by the sample plants. 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 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 five analyzed regulatory options under the two ownership cases described above.

As reported in *Table 8-2* and *Table 8-3,* EPA estimates that between 243 and 507 entities own 1,080 steam electric power plants (for Case 1 and Case 2, respectively). A typical parent entity on average is estimated to own 3 steam electric power plants (for both Case 1 and Case 2). The Agency estimates that between

110 (45 percent) and 191 (38 percent) parent entities are small under Case 1 and Case 2, respectively. These 110 and 191 small entities (*Table 8-2*) own 231 steam electric power plants (*Table 8-3*), or approximately 21 percent of all steam electric power plants. Across ownership types, cooperatives represent the largest share of small entities under Case 1 and Case 2 (89 and 94 percent, respectively); cooperatives account for the largest share of steam electric power plants owned by small entities (88 percent) under both Cases.

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

Ownership Type	Small Entity Size Standard	Case 1: Lower bound estimate of number of entities owning steam electric power plants[b]			Case 2: Upper bound estimate of number of entities owning steam electric power plants[b]		
		Total	Small[c]	% Small	Total	Small[c]	% Small
Cooperative	number of employees	29	26	89.7%	49	46	93.9%
Federal	assumed large	2	0	0.0%	4	0	0.0%
Investor-owned	number of employees[d]	97	28	28.9%	244	66	27.1%
Municipality	50,000 population served	65	36	55.4%	101	43	42.1%
Nonutility	number of employees[d]	36	19	52.8%	77	35	46.1%
Other Political Subdivision	50,000 population served	12	1	8.3%	30	1	3.3%
State	assumed large	2	0	0.0%	2	0	0.0%
Total		**243**	**110**	**45.3%**	**507**	**191**	**37.6%**

a. Nineteen plants are owned by a joint venture of two entities. One plant is owned by a joint venture of three entities.

b. Of these, 75 entities, 21 of which are small, own steam electric power plants that are expected to incur compliance technology costs under final regulatory Option D under both Case 1 and Case 2.

c. EPA was unable to determine the size of 16 parent entities; for this analysis, these entities are assumed to be small.

d. Entity size may be based on revenue, depending on the NAICS sector (see *Table 8-1*).
Source: U.S. EPA Analysis, 2015.

Table 8-3: Steam Electric Power Plants by Ownership Type and Size, 2015

Ownership Type	Number of Steam Electric Power Plants[a,b,c,d]		
	Total	Small	% Small
Cooperative	63	55	87.4%
Federal	15	0	0.0%
Investor-owned	681	95	14.0%
Municipality	122	46	37.7%
Nonutility	153	34	22.1%
Other Political Subdivisions	41	1	2.5%
State	5	0	0.0%
Total	**1,080**	**231**	**21.4%**

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, 214 steam electric power plants are expected to incur compliance technology costs under at least one regulatory option; 32 of these 214 steam electric power plants are owned by small entities.
Source: U.S. EPA Analysis, 2015.

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 final ELGs 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 final rule 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, 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, EPA categorized entities according to the magnitude of economic impacts they may incur as a result of the final ELGs. EPA identified entities for which annualized compliance costs are at least 1 percent and 3 percent of revenue. 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 1 percent of revenue are unlikely to face significant economic impacts, while entities with costs of at least 1 percent of revenue have a higher chance of facing significant economic impacts, and entities incurring costs of at least 3 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*, 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 Final Rule and Other Regulatory Options

As described above, EPA developed estimates of the number of small parent entities in the specified cost-to-revenue impact ranges using two weighting concepts:

- Case 1: Lower bound estimate of number of entities owning steam electric; upper bound estimate of total compliance costs that an entity may incur.
- Case 2: Upper bound estimate of number of entities owning steam electric power plants; lower bound estimate of total compliance costs that an entity may incur.

Table 8-4 summarizes the results of the analysis. As shown in the two tables, 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. EPA estimates that between 0 and 7 small entities owning steam electric power plants would incur costs exceeding 1 percent of revenue, and up to one small entity would incur costs of at least

3 percent of revenue, depending on the regulatory option. The Agency estimates that under the final BAT and PSES (Option D), 6 small entities (3 to 5 percent of small entities) would incur costs of at least 1 percent of revenue and one small municipal entity (2 to 3 percent) would incur costs of at least 3 percent of revenue.

On the basis of *percentage* of small entities by entity type, the analysis shows a small fraction of small business or government entities (between 0 and 11 percent) incurring an impact at either the 1 or 3 percent of revenue levels. Under Option D, between 9 and 11 percent of small government entities have costs exceeding 1 percent of revenue. The range reflects assumptions on whether different or the same entities own non-surveyed steam electric power plants.

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

Entity Type / Ownership Category	Case 1: Lower bound estimate of number of entities owning steam electric power plants (out of total of 110 small entities)				Case 2: Upper bound estimate of number of entities owning steam electric power plants (out of total of 191 small entities)			
	Cost ≥1% of Revenue		Cost ≥3% of Revenue		Cost ≥1% of Revenue		Cost ≥3% of Revenue	
	Number of Small Entities	% of Small Entities	Number of Small Entities	% of Small Entities	Number of Small Entities	% of Small Entities	Number of Small Entities	% of Small Entities
Option A								
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%
Municipality	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%
Other Political Subdivision	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Small Business[c]	***0***	***0.0%***	***0***	***0.0%***	***0***	***0.0%***	***0***	***0.0%***
Small Government[d]	***0***	***0.0%***	***0***	***0.0%***	***0***	***0.0%***	***0***	***0.0%***
Total	**0**	**0.0%**	**0**	**0.0%**	**0**	**0.0%**	**0**	**0.0%**
Option B								
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%
Municipality	1	2.8%	0	0.0%	1	2.3%	0	0.0%
Nonutility	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Other Political Subdivision	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Small Business[c]	***0***	***0.0%***	***0***	***0.0%***	***0***	***0.0%***	***0***	***0.0%***
Small Government[d]	***1***	***2.7%***	***0***	***0.0%***	***1***	***2.3%***	***0***	***0.0%***
Total	**1**	**0.9%**	**0**	**0.0%**	**1**	**0.5%**	**0**	**0.0%**
Option C								
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%
Municipality	2	5.6%	1	2.8%	2	4.7%	1	2.3%
Nonutility	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Other Political Subdivision	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Small Business[c]	***0***	***0.0%***	***0***	***0.0%***	***0***	***0.0%***	***0***	***0.0%***
Small Government[d]	***2***	***5.3%***	***1***	***2.6%***	***2***	***4.5%***	***1***	***2.2%***
Total	**2**	**1.8%**	**1**	**0.9%**	**2**	**1.0%**	**1**	**0.5%**

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

Entity Type / Ownership Category	Case 1: Lower bound estimate of number of entities owning steam electric power plants (out of total of 110 small entities)				Case 2: Upper bound estimate of number of entities owning steam electric power plants (out of total of 191 small entities)			
	Cost ≥1% of Revenue		Cost ≥3% of Revenue		Cost ≥1% of Revenue		Cost ≥3% of Revenue	
	Number of Small Entities	% of Small Entities	Number of Small Entities	% of Small Entities	Number of Small Entities	% of Small Entities	Number of Small Entities	% of Small Entities
Option D								
Cooperative	1	3.8%	0	0.0%	1	2.2%	0	0.0%
Investor-Owned	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Municipality	4	11.1%	1	2.8%	4	9.4%	1	2.3%
Nonutility	1	5.3%	0	0.0%	1	2.8%	0	0.0%
Other Political Subdivision	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Small Business[c]	***2***	***2.7%***	***0***	***0.0%***	***2***	***1.4%***	***0***	***0.0%***
Small Government[d]	***4***	***10.5%***	***1***	***2.6%***	***4***	***9.0%***	***1***	***2.2%***
Total	**6**	**5.4%**	**1**	**0.9%**	**6**	**3.1%**	**1**	**0.5%**
Option E								
Cooperative	2	7.7%	0	0.0%	2	4.4%	0	0.0%
Investor-Owned	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Municipality	4	11.1%	1	2.8%	4	9.4%	1	2.3%
Nonutility	1	5.3%	0	0.0%	1	2.8%	0	0.0%
Other Political Subdivision	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Small Business[c]	***3***	***4.1%***	***0***	***0.0%***	***3***	***2.0%***	***0***	***0.0%***
Small Government[d]	***4***	***10.5%***	***1***	***2.6%***	***4***	***9.0%***	***1***	***2.2%***
Total	**7**	**6.3%**	**1**	**0.9%**	**7**	**3.6%**	**1**	**0.5%**

a. The number of entities with cost-to-revenue impact of at least 3 percent is a subset of the number of entities with such ratios exceeding 1 percent.

b. Percentage values were calculated relative to the total of 110 (Case 1) and 191 (Case 2) small entities owning steam electric power plants regardless of whether these plants are expected to incur compliance technology costs under any of the regulatory options.

c. Small businesses include cooperatives, investor-owned utilities, and nonutilities.

d. Small governments include municipalities and other political subdivisions.
Source: U.S. EPA Analysis, 2015.

8.3 Uncertainties and Limitations

Despite EPA's use of the best available information and data available, 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. 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.
- EPA was unable to determine the size of 16 parent entities and assumed that these entities are small; this assumption may overstate the number of small entities that own steam electric power plants.

- To the extent that the information reported in the industry survey and/or publicly available sources for 2007, 2008, and 2009 and used in this analysis to determine entity size is not reflective of the actual 2015 values, the number of small parent entities of steam electric power plants may be over- or under-estimated.
- Similarly, the entity-level revenue values obtained from the industry survey, corporate and financial websites, or EIA databases are for 2007, 2008, and/or 2009. To the extent that actual 2015 entity revenue values are different from those estimated using data for 2007, 2008, and/or 2009, the impact of the final ELGs on parent entities of steam electric power plants may be over- or under-estimated.
- To the extent that the state implementation plans under the Clean Power Plan lead to outcomes that differ from the IPM runs, the number of small entities that own steam electric power plants may be lower or higher than analyzed in this chapter. Changes in the distribution of plant owners may differ if states choose to protect certain types of plants, as they have the flexibility to do so.
- As discussed in *Chapter 4* (Section 4.3) EPA did not account for changes in plant ownership that may have occurred since the industry survey was conducted. To the extent that such changes in ownership result in a different distribution of plant owners with respect to the types of entities or their size category, the impact of the final ELGs on parent entities of steam electric power plants may be over- or under-estimated.
- 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 final ELGs on small entities.
- As discussed in *Chapter 3*, the compliance costs used in this analysis reflect anticipated unit retirements, conversions, and repowerings announced through August 2014 scheduled to occur by 2023, and include projected conversions to dry systems in response to the final CCR rule. Projected changes that may result from the CPP rule are based on EPA's understanding of those effects at the time the ELG analyses were conducted, based on the proposed CPP rule analysis.[112] To the extent that actual unit retirements, conversions, and repowerings differ from anticipated changes, total annualized compliance costs may differ from actual costs.

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. In the preamble to this rule, EPA describes how, by establishing different BAT and PSES requirements for oil-fired generating units and small generating units (50 MW or less in capacity), the final ELGs reduce compliance costs for small entities that own plants with one or more such units. Based on the sensitivity analyses discussed in *Appendix C*, EPA estimates that 24 small entities incur compliance costs under Option D when units of all sizes have to meet the same limitations and standards (based on the scenario without CPP detailed in *Appendix B*); however, only 22 small entities incur compliance costs with the differentiated requirements.

[112] See memorandum in the docket for a comparison of the proposed and final CPP rules and a discussion of the implications of including the proposed CPP rule in the baseline as compared to the final CPP rule EPA promulgated on August 3, 2015. (DCN SE05983)

The implementation period built into the final ELGs (assumed for the purposes of assessing costs and economic impacts to occur between 2019 and 2023) is another way in which EPA considered the needs of small entities, as these entities may need time to incorporate compliance technology investments into their capital budgets.

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, 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.*, $141 million in 2013 dollars). Before promulgating a regulation for which a written statement is needed, UMRA section 205 generally requires 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. The provisions of section 205 do not apply when they are inconsistent with applicable law. Moreover, section 205 allows 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 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 EPA regulatory proposals with significant intergovernmental mandates, and informing, educating, and advising small governments on compliance with regulatory requirements.

EPA estimates that the *maximum* cost *in any one year* for compliance with the regulatory options to government entities (excluding federal government) range from $46.9 million under Option A to $177.7 million under Option E.[113,114] The final BAT and PSES (Option D) have maximum costs in any given year to government entities of $171.4 million. The *maximum* cost *in any given year* to the private sector range from $374.9 million under Option A to $1,467.9 million under Option E. Option D has maximum costs in any given year to the private sector of $1,335.1 million.

From these cost values, EPA determined that the final ELGs contain a federal mandate that may result in expenditures of $141 million (in 2013 dollars) or more for State, local, and Tribal governments, in the aggregate, or the private sector in any one year. Accordingly, under Section 202 of UMRA, EPA has prepared a written statement, presented in the preamble to the final ELGs, that addresses the requirements above. This chapter contains additional information to support that statement, including information on compliance and administrative costs, and on impacts to small governments.

Annualized costs presented in this UMRA analysis are calculated using the social cost framework presented in *Chapter 12: Assessment of Total Social Costs* of the *Benefit and Cost Analysis for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* report (*BCA*) (U.S. EPA, 2015a). Specifically, this analysis uses costs in 2015 stated in 2013 dollars and accounts for costs in the year they are anticipated to be incurred. As discussed in *Chapter 10: Other Administrative Requirements* (see *Section 10.7: Paperwork Reduction Act of 1995*) in this document, the final ELGs would not significantly change the reporting and recordkeeping burden for the review, oversight, and administration of the rule relative to existing requirements; consequently, NPDES permitting authorities are expected to

[113] Maximum costs are costs incurred by the entire universe of steam electric plants in a given year of occurrence under a given regulatory option.

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

incur minimal additional costs to administer this rule. The only cost that government entities would potentially incur as the result of this rule is the cost to implement control technologies at power plants they own (which already incorporate any additional monitoring costs). For more details on how social costs were developed, see BCA *Chapter 12.*

For this analysis, EPA assessed the impact of the regulatory options on government entities, small government entities, and the private sector; the results of this analysis are presented in this chapter.

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 15 of the 1,080 steam electric power plants and is expected to incur compliance costs under the regulatory options. Additionally, in evaluating the magnitude of the impact of the options on government entities, EPA considered only *compliance costs* incurred by government entities owning steam electric power plants. As discussed earlier, government entities would not incur significant incremental *administrative costs* to implement the rule, regardless of whether or not they own steam electric power plants.

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 Final ELGs on Small Entities – Regulatory Flexibility Act (RFA) Analysis*.

Table 9-1 summarizes the number of State, local and Tribal government entities and the number of steam electric power plants they own.

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

Entity Type	Parent Entities[a]	Steam electric power plants[b]
Municipality	65	122
Other Political Subdivision	12	41
State	2	5
Tribal	0	0
Total	**79**	**168**

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 weighted estimates. See *TDD* for discussion on development of plant sample weights.

Source: U.S. EPA Analysis, 2015

Out of 1,080 steam electric power plants, 168 are owned by 79 government entities.[115] The majority (73 percent) of these government-owned plants are owned by municipalities, followed by other political subdivisions (24 percent), and State governments (3 percent).

[115] Counts exclude federal government entities and steam electric 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: Cost and Economic Impact Screening Analyses*.

As presented in *Table 9-2*, government entities are projected to incur the lowest compliance costs under Option A and the highest compliance costs under Option E.

Under Option D, compliance costs for government entities are approximately $35.4 million in the aggregate, with an average of $0.2 million per plant. Municipalities account for the largest share of this cost (43 percent), followed by state government entities (39 percent) and other political subdivisions (17 percent). The average cost per plant to States is $2.7 million, compared to $0.1 million and $0.2 million for plants owned by municipalities and other political subdivisions, respectively. The maximum annualized compliance costs estimated to be incurred by any single government-owned plant is $10.6 million for a State-owned plant, $3.3 million for a municipal plant, and $4.2 million for plants owned by other political subdivisions. The average cost per MW of government-owned generating capacity is estimated to be $550 per MW, with the highest average unit cost incurred by States ($2,806 per MW) and the lowest average unit cost incurred by other political subdivisions ($247 per MW).

Table 9-2: Compliance Costs to Government Entities Owning Steam Electric Power Plants (Millions; $2013)

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 A					
Municipality	122	$3.3	$98	$0.0	$1.1
Other Political Subdivision	41	$0.0	$0	$0.0	$0.0
State	5	$2.5	$521	$0.5	$2.5
Total	**168**	**$5.9**	**$91**	**$0.0**	**$2.5**
Option B					
Municipality	122	$6.6	$193	$0.1	$1.7
Other Political Subdivision	41	$0.0	$0	$0.0	$0.0
State	5	$4.6	$944	$0.9	$3.7
Total	**168**	**$11.2**	**$174**	**$0.1**	**$3.7**
Option C					
Municipality	122	$7.8	$226	$0.1	$2.3
Other Political Subdivision	41	$0.0	$0	$0.0	$0.0
State	5	$11.5	$2,357	$2.3	$10.6
Total	**168**	**$19.3**	**$299**	**$0.1**	**$10.6**
Option D					
Municipality	122	$15.5	$452	$0.1	$3.3
Other Political Subdivision	41	$6.2	$247	$0.2	$4.2
State	5	$13.7	$2,806	$2.7	$10.6
Total	**168**	**$35.4**	**$550**	**$0.2**	**$10.6**

Table 9-2: Compliance Costs to Government Entities Owning Steam Electric Power Plants (Millions; $2013)

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 E					
Municipality	122	$17.9	$523	$0.1	$3.5
Other Political Subdivision	41	$6.9	$273	$0.2	$4.2
State	5	$13.7	$2,806	$2.7	$10.6
Total	**168**	**$38.5**	**$598**	**$0.2**	**$10.6**

a. Plant counts and cost values are weighted estimates. See *TDD* for discussion on the development of plant sample weights.

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, 2015.

9.2 UMRA Analysis of Impact on Small Governments

As part of the UMRA analysis, EPA also assessed whether the regulatory options would significantly and uniquely affect small governments. To assess whether the final ELGs would affect small governments in a way that is disproportionately burdensome in comparison to the effect on large governments, EPA compared total costs and costs per plant estimated to be incurred by small governments with those values estimated to be incurred by large governments. EPA also compared the 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 cost per plant.

Out of 1,080 government-owned steam electric power plants, EPA identified 47 plants that are owned by 37 small government entities. These 41 plants constitute approximately 28 percent of all government-owned plants.[116]

Table 9-3: 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	29	36	65	76	46	**122**
Other Political Subdivision	11	1	12	40	1	**41**
State	2	0	2	5	0	**5**
Total	**42**	**37**	**79**	**121**	**47**	**168**

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 weighted estimates. See *TDD* for discussion on development of plant sample weights.
Source: U.S. EPA Analysis, 2015.

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

As presented in *Table 9-4*, compliance costs are the lowest and associated regulatory impacts are the smallest under Option A and the largest under Option E. Generally, compliance costs are lower for small governments compared to costs for large governments and to small private entities; this trend holds in the aggregate and on a per plant basis under all regulatory options.

For Option D, total annualized compliance costs are approximately $4.4 million for small government entities, compared to $31.0 million for large government entities and $26.2 million for small private entities. EPA estimates that, under Option D, a small government entity would, on average, incur $0.1 million in compliance costs per plant (but no more than $2.3 million per plant) compared to $0.3 million per plant (but no more than $10.6 million per plant) for plants owned by large governments, and $0.1 million per plant (but no more than $4.1 million per plant) for those owned by small private entities. On a per MW of capacity basis, small government entities are projected to incur an average cost of $1,179 per MW under Option D, while for large government and small private entities unit costs are estimated to be $458 per MW and $370 per MW, respectively.

As discussed in the preceding paragraph and presented in *Table 9-4*, EPA estimates total costs to small government entities, in the aggregate, to be lower than costs to large government or small private entities, in the aggregate and on a per plant basis. On a per MW basis, small governments face costs that tend to be higher than large governments and private entities. However, the fact that the average compliance cost per MW of plant capacity owned by small governments tends to be higher compared to that for plants owned by large governments or by small private entities, only shows that, on average, plants owned by small governments tend to be smaller compared to those owned by large governments or small private entities and reflects economies of scale in control technologies costs. Given these results, EPA finds that small governments would not be significantly or uniquely affected by the final ELGs.

Table 9-4: Compliance Costs for Electric Generators by Ownership Type and Size ($2013)

Ownership Type	Entity Size	Number of Plants (weighted)[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)[d]
Option A						
Government (excl. federal)	Small	47	$0.4	$104	$0.01	$0.4
	Large	121	$5.5	$81	$0.04	$2.5
Private	Small	185	$4.2	$59	$0.02	$1.3
	Large	713	$80.6	$138	$0.11	$8.8
All Plants		**1,080**	**$116.9**	**$155**	**$0.11**	**$17.7**
Option B						
Government (excl. federal)	Small	47	$0.9	$226	$0.02	$0.9
	Large	121	$10.4	$153	$0.08	$3.7
Private	Small	185	$9.9	$140	$0.05	$3.2
	Large	713	$138.0	$237	$0.19	$11.7
All Plants		**1,080**	**$194.7**	**$259**	**$0.18**	**$22.4**
Option C						
Government (excl. federal)	Small	47	$2.0	$529	$0.05	$2.3
	Large	121	$17.3	$255	$0.14	$10.6
Private	Small	185	$16.0	$226	$0.08	$3.3
	Large	713	$309.1	$530	$0.43	$16.7

Table 9-4: Compliance Costs for Electric Generators by Ownership Type and Size ($2013)

Ownership Type	Entity Size	Number of Plants (weighted)[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)[d]
All Plants		**1,080**	**$379.9**	**$505**	**$0.35**	**$22.4**
			Option D			
Government (excl. federal)	Small	47	$4.4	$1,179	$0.10	$2.3
	Large	121	$31.0	$458	$0.25	$10.6
Private	Small	185	$26.2	$370	$0.14	$4.1
	Large	713	$374.0	$642	$0.52	$16.7
All Plants		**1,080**	**$471.2**	**$626**	**$0.43**	**$22.4**
			Option E			
Government (excl. federal)	Small	47	$5.5	$1,446	$0.12	$3.5
	Large	121	$33.1	$489	$0.27	$10.6
Private	Small	185	$29.2	$411	$0.15	$4.2
	Large	713	$422.0	$724	$0.58	$16.7
All Plants		**1,080**	**$525.8**	**$698**	**$0.48**	**$22.4**

a. Plant counts and cost values are sample weighted estimates.

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 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.

d. Values reflect maximum of un-weighted costs to surveyed plants only.
Source: U.S. EPA Analysis, 2015.

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.

EPA estimates total annualized pre-tax compliance costs for private entities to range from $84.7 million under Option A to $451.2 million under Option E (*Table 9-5*). Under Option D, EPA estimates that private entities will incur $400.2 million in total annualized pre-tax compliance costs, with maximum costs to private entities of $1,335 million in 2021.

Table 9-5: Compliance Costs for Electric Generators by Ownership Type ($2013)

Ownership Type	Total Annualized Costs	Maximum One-Year Costs	Year of Maximum Costs
	Option A		
Government (excl. federal) and Cooperatives	$5.9	$46.9	2019
Private	$84.7	$374.9	2021
	Option B		
Government (excl. federal) and Cooperatives	$11.2	$69.8	2019
Private	$147.9	$600.1	2021

Table 9-5: Compliance Costs for Electric Generators by Ownership Type ($2013)

Ownership Type	Total Annualized Costs	Maximum One-Year Costs	Year of Maximum Costs
Option C			
Government (excl. federal) and Cooperatives	$19.3	$135.4	2019
Private	$325.0	$1,219.4	2021
Option D			
Government (excl. federal) and Cooperatives	$35.4	$171.4	2019
Private	$400.2	$1,335.1	2021
Option E			
Government (excl. federal) and Cooperatives	$38.5	$177.7	2019
Private	$451.2	$1,467.9	2021

Source: U.S. EPA Analysis, 2015.

9.4 UMRA Analysis Summary

EPA estimates that the final BAT and PSES (Option D) will result in expenditures of at least $141 million for State and local government entities, in the aggregate, or for the private sector in any one year.

Total annualized compliance costs to government entities are estimated at approximately $35 million under Option D, with a maximum one-year compliance cost of $171 million in 2019 (see *Table 9-5*). Private entities are projected to incur annualized compliance costs of $400 million under Option D, with a maximum of $1,335 million in 2021.

The timing of 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 *Chapter 3* in this report and BCA *Chapter 11* for more details on the technology implementation years and assumptions on the timing of cost incurrence.

As discussed earlier, the final ELGs will result in minimal changes in the reporting and recordkeeping requirements currently in effect for steam electric dischargers (*e.g.*, some steam electric power plants may need to conduct additional monitoring, as discussed in the *TDD*; the costs for the additional monitoring are already included in O&M costs used for this analysis). Beyond these minimal costs, neither permitted plants nor permitting authorities are expected to incur significant additional administrative costs as the result of the final ELGs.

Note that, consistent with Section 205, EPA identified and considered a number of alternative regulatory options to determine BAT/BADCT and assessed their effects on state, local, and tribal governments and the private sector. By differentiating requirements for oil-fired generating units and units of 50 MW or less, EPA reduced the number of government entities incurring costs (see *Appendix C* for details).

10 Other Administrative Requirements

This chapter presents analyses conducted in support of the final ELGs to address the requirements of Executive Orders and Acts applicable to this rule. These analyses complement EPA's assessment of the compliance costs, economic impacts, and economic achievability of the final ELGs, and other analyses done in accordance with Regulatory Flexibility Act (RFA) and Unfunded Mandates Reform Act (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 12866 (58 FR 51735, October 4, 1993), 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, EPA determined that the final ELGs are an "economically significant regulatory action" because it is likely to have an annual effect on the economy of $100 million or more. As such, the action is subject to review by the Office of Management and Budget (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.

EPA prepared an analysis of the potential benefits and costs associated with this action; this analysis is described in BCA *Chapter 12: Benefits and Social Costs* (U.S. EPA, 2015a).

As detailed in earlier chapters of this report, EPA also assessed the impacts of the final ELGs 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 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order (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 EPA guidance on considering EJ in the development of regulatory actions (U.S. EPA, 2015d), EPA examined whether the benefits from the final ELGs may be differentially distributed among population subgroups in the affected areas. As described in *Chapter 14* of the BCA document (U.S. EPA, 2015a), EPA conducted two types of analyses to evaluate the EJ implications of the final ELGs: (1) summarizing the demographic characteristics of the households living in proximity to reaches that receive steam electric power plant discharges and thus are likely to be affected by the plant discharges and 2) 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, EPA determined that the final ELGs will not deny communities from the benefits of environmental improvements expected to result from compliance with the more stringent effluent limits. In fact, the distribution of avoided adverse health outcomes and benefits suggests that poor and minority communities may receive a greater share of the benefits from the final ELGs than their representation in the affected populations. The final ELGs may thus help redress environmental inequities that may exist in the baseline.

10.3 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 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.

The final ELGs are an economically significant regulation as defined under Executive Order 12866, but the environmental health risks or safety risks addressed by this action do not present a *disproportionate* risk to children.

As detailed in the BCA document (U.S. EPA, 2015a), EPA identified several ways in which the final ELGs would benefit children, including by reducing health risk from exposure to pollutants present in steam electric power plant discharges. In particular, EPA quantified the benefits associated with reduced IQ losses from lead exposure among pre-school children and from mercury exposure *in-utero* resulting from maternal fish consumption under all five regulatory options. 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.

EPA estimated that the final limitations (Option D) would reduce lead exposure (from fish consumption) for an average of 3.3 million children annually, and would reduce mercury exposure (from maternal fish consumption) for an average of 419,000 babies born annually. EPA estimated that two fewer children in the affected population would have very high blood lead concentrations under Option D. The annual benefits of avoided IQ loss and compensatory education from children lead and mercury exposure under Option D range between $3.8 million and $5.7 million using a 3 percent discount rate. Chapter 3 in the BCA document provides further details (U.S. EPA, 2015a).

EPA did not quantify additional benefits to children from reduced exposure to steam electric pollutant discharges due to data limitations. These include the reduction in the incidence or severity of other health effects from exposure to lead (such as slowed or delayed growth, hyperactivity, behavioral difficulties, motor skills, and neonatal mortality), mercury (such as developmental delays, visual-spatial and motor function problems, and elevated blood pressure), and other pollutants including arsenic, boron, cadmium, copper, nickel, selenium, thallium, and zinc.

10.4 Executive Order 13132: Federalism

Executive Order 13132 (64 FR 43255, August 10, 1999) requires 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, 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 EPA consults with State and local officials early in the process of developing the regulation. 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.

EPA has concluded that this action would have federalism implications, because it may impose substantial direct compliance costs on State or local governments, and the Federal government would not provide the funds necessary to pay those costs.

As discussed in earlier chapters of this document, EPA anticipates that this final action would not impose a significant incremental administrative burden on States from issuing, reviewing, and overseeing compliance with discharge requirements. However, EPA has identified 168 steam electric power plants that are owned by State or local government entities. EPA estimates that the maximum compliance cost in any one year to governments (excluding federal government) ranges from $46.9 million under Option A to $177.7 million under Option E (see *Chapter 9: Unfunded Mandates Reform Act (UMRA)* for details). The final BAT and PSES (Option D) have maximum costs in any one year to governments of $171.4 million. Based on this information, EPA finds that the action would impose substantial direct compliance costs on State or local governments.

EPA consulted with State and local officials early in the process of developing the final action to permit them to have meaningful and timely input into its development. The preamble to this final rule describes these consultations. Additionally, EPA received comments from State and local government representatives in response to the proposed rule and considered these comments in evaluating options for the final rule.

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

Executive Order 13175 (65 FR 67249, November 6, 2000) requires 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 final ELGs do not have tribal implications. They would not have substantial direct effects on tribal governments, on the relationship between the federal government and Indian Tribes, or on the distribution of power and responsibilities between the Federal government and Indian Tribes, as specified in Executive Order 13175. EPA's analyses show that no plant expected to be affected by the final ELGs is owned by tribal governments and thus this regulation does not affect Tribes in any way in the foreseeable future. Further, no tribal governments are currently authorized pursuant to section 402(b) of the CWA to implement the NPDES program. Consequently, Executive Order 13175 does not apply to this regulation.

Although Executive Order 13175 does not apply to this action, EPA consulted with tribal officials in developing this action. These consultations are described in the preamble to the regulation.

10.6 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 expected 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." [117] Those criteria include:

[117] Executive Order 13211 was issued May 18, 2002. The Office of Management and Budget later released an Implementation Guidance memorandum on July 13, 2002.

- 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;
- 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.

Of the potential significant adverse effects on the supply, distribution, or use of energy (listed above) only four apply to the final ELGs. Through increases in the cost of generating electricity and shifts in the types of generators employed, the final ELGs 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. EPA used the results from the national electricity market analyses conducted for two regulatory options (Options B and D) to analyze the final ELGs for each of these potential effects (see *Chapter 5: Electricity Market Analyses*).

10.6.1 Impact on Electricity Generation

The electricity market analyses (*Chapter 5*) estimate that generation from steam electric power plants to which the final rule applies will decrease by about 0.2 percent, relative to baseline generation, for Option D, but that this reduction will be offset by increased production from other plants, resulting in a small net decrease in overall production.

Thus, the market analyses estimate that, in the aggregate, the electricity market would generate 636 million kWh less electricity in 2020 (technology implementation year; short run) and 846 million kWh less electricity in 2030 (the steady-state post-compliance year; long run) under Option D than it would in the baseline case. These reductions amount to 0.02 percent of baseline electricity generation and likely reflect improved efficiency of transmission and distribution to meet a constant electricity demand.

Under Option D and in both the short and long run, the effect of the final ELGs is less than the 1 billion kWh reduction required for the regulation to be considered a significant energy action.

10.6.2 Impact on Electricity Generating Capacity

As documented in *Chapter 5*, EPA's electricity market analysis estimated that by 2030 the final rule will result in net retirement of 842 MW of generating capacity, which exceeds the threshold of 500 MW of installed capacity identified in the OMB guidance as an indicator of significant adverse effect. Specifically, the final rule will lead to early retirement of 4 electricity generating units accounting for 942MW of capacity. These retirements are offset by 100 MW of avoided retirement of capacity otherwise projected to retire by 2030. The retirements involve older, less efficient generating units with very low capacity utilization rates. Specifically, projected capacity utilization in 2030 for the four units, absent the final rule, is less than 4 percent; it is less than 0.5 percent for two of those units. The 842 MW of net retired capacity is offset by 933 in new capacity additions.

Because the final rule could lead to a net loss of more than 500 MW of installed generating capacity, EPA finds that the final rule would constitute a significant energy action and may cause a significant adverse effect based on the criterion of reduced electric generating capacity. Despite this finding, EPA notes, however, that the impact of lost electric generating capacity is comparatively minor because of the projected low capacity utilization and associated low electricity supply contribution from those electric generating units that are projected to retire.

10.6.3 Cost of Energy Production

Based on the IPM analysis results, EPA estimated that the final rule would not significantly affect the total cost of electricity production in either the short or the long run. At the national level, in the short run (2020) and in the long run (2030), total electricity generation costs (fuel, variable O&M, fixed O&M and capital) under Option D would increase by 0.5 and 0.4 percent, respectively. At the regional level, the change in electricity generation costs varies, ranging from increases of 0.2 percent in WECC to 0.9 percent in MRO in 2020; and a 0.2 percent reduction in WECC to an increase of 0.5 percent in RFC in 2030. Consequently, no region would experience energy price increases of more than 1 percent as a result of the final ELGs in either the short or the long run. Consequently, EPA does not believe that the final ELGs constitute a "significant energy action" in terms of estimated potential effects on the cost of energy production.

10.6.4 Dependence on Foreign Supply of Energy

EPA's electricity market analyses did not support explicit consideration of the effects of the final ELGs on foreign imports of energy. However, the final ELGs 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.

As presented in *Table 10-1,* under Option D, coal-based electricity generation along with coal consumption is expected to decline by 0.3 percent. Generation using several other fuels is expected to either increase (*i.e.*, biomass, natural gas, waste coal, wind) or decrease (oil and solar) depending on the fuel. Consequently, consumption of those fuels is expected to respectively increase or decrease, however modestly. With the exceptions of oil (2.8 percent reduction) and waste coal (3.3 percent increase), estimated non-zero changes in fuel use are less than 0.4 percent in absolute value. Changes in electricity generation follows these trends with generation using other fuels not expected to change by more than 0.4 percent.

Given the very small increases in usage of fuel other than waste coal, it is reasonable to assume that the 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 any of these fuels. Therefore, EPA concludes that the final ELGs would not significantly increase dependence on foreign supplies of energy.

Table 10-1: Total Market-Level Capacity, Generation, and Fuel Use by Fuel Type for Option D[a]

	Generating Capacity (MW)			Electricity Generation (GWh)			Fuel Consumption (TBtu)		
Fuel Type	**Baseline**	**Option D**	**% Change**	**Baseline**	**Option D**	**% Change**	**Baseline**	**Option D**	**% Change**
Biomass	6,883	6,204	-9.9%	19,795	19,880	0.4%	270	271	0.4%
Coal	201,658	200,156	-0.7%	1,197,846	1,194,570	-0.3%	11,516	11,481	-0.3%
Fossil Waste	412	412	0.0%	2,204	2,204	0.0%	22	22	0.0%
Geothermal	4,856	4,856	0.0%	33,950	33,950	0.0%	674	674	0.0%
Hydro	101,045	101,045	0.0%	280,431	280,328	0.0%	0	0	NA
Landfill Gas	2,034	2,034	0.0%	10,414	10,414	0.0%	146	146	0.0%
MSW	2,356	2,356	0.0%	14,648	14,648	0.0%	264	264	0.0%
Natural Gas	443,639	445,207	0.4%	1,393,644	1,395,608	0.1%	9,890	9,898	0.1%
Non-Fossil	1,628	1,628	0.0%	8,749	8,749	0.0%	90	90	0.0%
Nuclear	102,388	102,388	0.0%	797,305	797,305	0.0%	8,336	8,336	0.0%
Oil	35,555	35,091	-1.3%	12	12	-2.6%	0	0	-2.8%
Pet. Coke	1,120	1,120	0.0%	4,824	4,824	0.0%	50	50	0.0%
Solar	12,630	12,620	-0.1%	22,118	22,099	-0.1%	115	115	-0.2%
Waste Coal	1,401	1,444	3.1%	10,139	10,450	3.1%	109	113	3.3%
Wind	90,825	90,850	0.0%	255,564	255,756	0.1%	936	938	0.2%
Total	**564,791**	**562,202**	**-0.5%**	**2,658,001**	**2,655,190**	**-0.1%**	**22,528**	**22,500**	**-0.1%**

a. Numbers may not add up due to rounding.
Source: U.S. EPA Analysis, 2015.

10.6.5 Overall E.O. 13211 Finding

From these analyses, EPA concludes that the final ELGs would not have a *significant adverse effect* at a national or regional level under Executive Order 13211. Namely, the Agency's analysis found that the final ELGs 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, and therefore would not constitute a significant regulatory action under Executive Order 13211.As a result, EPA did not prepare a Statement of Energy Effects. For more detail on effects of the final ELGs on electricity markets, see *Chapter 5*.

10.7 Paperwork Reduction Act of 1995

The Paperwork Reduction Act of 1995 (PRA) (superseding the PRA of 1980) is implemented by the Office of Management and Budget (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.[118]

The final ELGs 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.

EPA estimated small changes in monitoring costs due to additional metals for which EPA is proposing limits and standards; the Agency accounted for these costs as part of its analysis of the economic impacts of the final ELGs (see *Chapter 3: Compliance Costs*). However, plants would also realize savings by no longer monitoring effluent that would no longer occur under the final ELGs. The net effects of the changes in monitoring and reporting are expected to be minimal.

Further, EPA anticipates that the final rule will result in no additional costs to permitting authorities. The final rule would not change permit application requirements or the associated review, it would not increase the number of permits issued to steam electric power plants, and nor would it increase the efforts involved in developing or reviewing such permits. As explained further in the preamble to this rule, in the absence of nationally applicable BAT requirements, permitting authorities are directed to use best professional judgment (BPJ) to establish site-specific requirements. Where BPJ is used, the permit writer must consider the same statutory factors EPA would use in promulgating a national effluent guideline regulation, but apply the factors to the circumstances specific to the permit applicant (U.S. EPA, 2010c).[119] Further, developing limits based on BPJ can result in inconsistencies across permits, which in turn can lead to protracted negotiations over the appropriate levels and a potentially costly review/revision processes. Permitting authorities establishing site-specific requirements spend significant effort and resources.[120] Furthermore, BPJ-based limitations can also

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

[119] The factors to be considered when assessing best available technology economically achievable (BAT), include "the age of equipment and facilities involved, the process employed, the engineering aspects of the application of various types of control techniques, process changes, the cost of achieving such effluent reduction, non-water quality environmental impact (including energy requirements), and such other factors as the Administrator deems appropriate" [CWA section 304(b)(2)(B)]

[120] The number of sources and tools that permit writers may consult to set limits based on BPJ highlight the potential burden. According to the permit writer guidance (U.S. EPA, 2010c), these sources include: (1) Permit file information (current and previous NPDES application forms; previous NPDES permit and fact sheet; discharge monitoring reports; compliance inspection reports); (2) Information from existing facilities and permits (NPDES permits issued to other facilities in the same region or state, or that include case-by-case limitations for the same pollutants; toxicity reduction evaluations for selected industries; other media permit files (*e.g.*, Resource Conservation and Recovery Act permit applications and Spill Prevention Countermeasure and Control plans); ICIS-NPDES data; literature (*e.g.*, technical journals and books)); (3) ELG development and planning information (industry experts within EPA headquarters, EPA Regions, and states; Development Documents, CWA section 308 questionnaires, screening and verification data, proposed and final regulations, contractor's

be more burdensome for permit applicants and other parties that engage in the process. Establishing nationally applicable BAT requirements that eliminate the need to develop BPJ-based limitations would make permitting easier and less costly in these respects. As explained in the preamble to this rule, permitting authorities would be required to determine for one permit cycle, on a facility specific basis, what date is "as soon as possible." This one time burden, however, would be no more excessive than the existing burden to develop technology-based effluent limitations on a BPJ basis; in fact, it would likely be less burdensome. Nevertheless, EPA conservatively estimated no net change increase or decrease in the costs burden to federal or state governments associated with the final ELGs.

10.8 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 directs EPA to provide Congress, through the Office of Management and Budget (OMB), explanations when the Agency decides not to use available and applicable voluntary consensus standards.

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

reports, and project officer contacts; EPA's Technical Support Documents and records supporting EPA's biennial effluent guidelines program plans); (4) Statistical guidance (ELG Technical Development Support Documents); (5) Economics guidance (Protocol and Workbook for Determining Economic Achievability for NPDES Permits; BCT Cost Test Guidance).

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B Analyses for Alternate Scenario without CPP Rule

This appendix presents the results of EPA's analysis of an alternate scenario with a baseline that excludes the effects of the CPP rule. Results are presented following the order and format used in the main document for the analysis of the scenario including the effects of the CPP rule.

B.1 Compliance Costs

Table B-1: Counts of Steam Electric Power Plants Potentially Incurring Costs and Their Total Generating Capacity by Estimated Technology Implementation Year for Scenario without CPP (based on Option E)

Technology Implementation Year	Plant Counts[a]		Total Capacity	
	Counts	% of Total	Capacity (MW)	% of Total
2019	47	24.1%	54,163	23.5%
2020	38	19.5%	42,367	18.4%
2021	31	15.9%	39,622	17.2%
2022	40	20.5%	44,869	19.5%
2023	39	20.0%	49,310	21.4%
Total	**195**	**100.0%**	**230,330**	**100.0%**

a. Out of 1,080 steam electric power plants in the total universe.
Source: U.S. EPA Analysis, 2015.

As presented in Table B-2, for the scenario without CPP, EPA estimates that, on a *pre-tax* basis, steam electric power plants would incur annualized costs of meeting the final ELGs ranging from $142.7 million under Option A to $732.3 million under Option E. On an *after-tax* basis, the costs range from $106.1 million to $504.5 million.[121] EPA estimates the total annualized after-tax compliance costs of the option selected for the final limitations for existing plants (Option D) to be $455.3 million.

Table B-2: Total Annualized Compliance Costs for Scenario without CPP (in millions, $2013, at 2015)

Scenario and ELG 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
Option A	$78.0	$0.0	$64.7	$142.7	$57.6	$0.0	$48.6	$106.1
Option B	$143.7	$0.0	$102.0	$245.8	$105.6	$0.0	$75.8	$181.3
Option C	$304.3	$0.0	$181.3	$485.6	$208.1	$0.0	$126.2	$334.2
Option D	$388.5	$0.0	$270.2	$658.7	$266.9	$0.0	$188.4	$455.3
Option E	$432.3	$0.0	$300.0	$732.3	$296.4	$0.0	$208.1	$504.5

a. Initial one-time cost (other than capital technology costs), if applicable, consist of a one-time cost to close bottom ash system.

Source: U.S. EPA Analysis, 2015.

121 The compliance costs used in this analysis reflect anticipated unit retirements, conversions, and repowerings announced through August 2014 and scheduled to occur by 2023 but not changes anticipated as a result of the CPP rule.

Table B-3 reports costs at the level of a NERC region for the scenario without CPP. Annualized after-tax compliance costs are highest in the SERC and RFC regions for all regulatory options, whereas two NERC regions, ASCC and HICC, have no costs for any of the five options EPA analyzed as part of final rule development.

Table B-3: Annualized Compliance Costs by NERC Region for Scenario Without CPP (in millions, $2013, at 2015)

	Pre-Tax Compliance Costs				After-Tax Compliance Costs			
NERC Region[a]	Capital Technology	Other Initial One-Time[a]	Total O&M	Total	Capital Technology	Other Initial One-Time[a]	Total O&M	Total
Option A								
ASCC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
FRCC	$0.6	$0.0	$0.9	$1.5	$0.6	$0.0	$0.6	$1.2
HICC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
MRO	$1.6	$0.0	$0.9	$2.5	$1.4	$0.0	$0.9	$2.3
NPCC	$0.1	$0.0	$0.1	$0.2	$0.1	$0.0	$0.1	$0.1
RFC	$23.0	$0.0	$13.9	$36.9	$14.8	$0.0	$8.9	$23.7
SERC	$48.6	$0.0	$47.9	$96.6	$37.9	$0.0	$37.3	$75.2
SPP	$1.5	$0.0	$0.4	$1.9	$0.9	$0.0	$0.3	$1.2
TRE	$1.3	$0.0	$0.7	$2.1	$1.1	$0.0	$0.6	$1.8
WECC	$1.2	$0.0	($0.2)	$1.0	$0.8	$0.0	($0.1)	$0.6
Total	**$78.0**	**$0.0**	**$64.7**	**$142.7**	**$57.6**	**$0.0**	**$48.6**	**$106.1**
Option B								
ASCC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
FRCC	$5.7	$0.0	$4.2	$9.9	$4.6	$0.0	$3.1	$7.7
HICC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
MRO	$2.5	$0.0	$1.5	$3.9	$2.3	$0.0	$1.4	$3.7
NPCC	$0.6	$0.0	$0.6	$1.2	$0.3	$0.0	$0.4	$0.7
RFC	$49.6	$0.0	$28.4	$78.0	$31.8	$0.0	$18.3	$50.2
SERC	$78.6	$0.0	$64.4	$143.1	$61.7	$0.0	$50.3	$112.0
SPP	$2.9	$0.0	$1.3	$4.2	$1.8	$0.0	$0.8	$2.6
TRE	$2.2	$0.0	$1.6	$3.8	$1.9	$0.0	$1.4	$3.3
WECC	$1.6	$0.0	$0.0	$1.6	$1.0	$0.0	$0.0	$1.0
Total	**$143.7**	**$0.0**	**$102.0**	**$245.8**	**$105.6**	**$0.0**	**$75.8**	**$181.3**
Option C								
ASCC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
FRCC	$5.7	$0.0	$4.2	$9.9	$4.6	$0.0	$3.1	$7.7
HICC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
MRO	$9.5	$0.0	$3.7	$13.2	$6.8	$0.0	$2.5	$9.3
NPCC	$0.6	$0.0	$0.6	$1.2	$0.3	$0.0	$0.4	$0.7
RFC	$133.2	$0.0	$70.1	$203.3	$83.1	$0.0	$44.0	$127.1
SERC	$127.6	$0.0	$90.5	$218.1	$94.6	$0.0	$67.8	$162.5
SPP	$15.8	$0.0	$7.3	$23.1	$10.0	$0.0	$4.6	$14.7
TRE	$8.7	$0.0	$4.0	$12.8	$6.5	$0.0	$3.1	$9.6
WECC	$3.1	$0.0	$0.9	$4.0	$2.0	$0.0	$0.6	$2.6
Total	**$304.3**	**$0.0**	**$181.3**	**$485.6**	**$208.1**	**$0.0**	**$126.2**	**$334.2**

Table B-3: Annualized Compliance Costs by NERC Region for Scenario Without CPP (in millions, $2013, at 2015)

	Pre-Tax Compliance Costs				After-Tax Compliance Costs			
NERC Region[a]	Capital Technology	Other Initial One-Time[a]	Total O&M	Total	Capital Technology	Other Initial One-Time[a]	Total O&M	Total
Option D								
ASCC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
FRCC	$5.7	$0.0	$4.2	$9.9	$4.6	$0.0	$3.1	$7.7
HICC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
MRO	$20.6	$0.0	$15.2	$35.9	$16.5	$0.0	$12.5	$28.9
NPCC	$5.9	$0.0	$6.4	$12.3	$3.5	$0.0	$3.8	$7.4
RFC	$162.8	$0.0	$97.9	$260.7	$101.7	$0.0	$61.9	$163.6
SERC	$152.3	$0.0	$121.4	$273.7	$112.5	$0.0	$89.8	$202.3
SPP	$22.8	$0.0	$15.8	$38.6	$15.0	$0.0	$10.5	$25.5
TRE	$8.7	$0.0	$4.0	$12.8	$6.5	$0.0	$3.1	$9.6
WECC	$9.6	$0.0	$5.3	$14.9	$6.6	$0.0	$3.7	$10.2
Total	**$388.5**	**$0.0**	**$270.2**	**$658.7**	**$266.9**	**$0.0**	**$188.4**	**$455.3**
Option E								
ASCC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
FRCC	$7.3	$0.0	$4.9	$12.2	$6.0	$0.0	$3.9	$9.9
HICC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
MRO	$24.8	$0.0	$17.2	$41.9	$19.5	$0.0	$13.9	$33.5
NPCC	$7.4	$0.0	$7.0	$14.4	$4.4	$0.0	$4.2	$8.7
RFC	$183.2	$0.0	$113.7	$296.9	$114.4	$0.0	$71.6	$186.0
SERC	$162.1	$0.0	$127.6	$289.6	$119.2	$0.0	$93.9	$213.1
SPP	$26.7	$0.0	$18.2	$45.0	$17.7	$0.0	$12.1	$29.9
TRE	$10.9	$0.0	$5.8	$16.7	$8.2	$0.0	$4.6	$12.8
WECC	$10.0	$0.0	$5.5	$15.5	$6.9	$0.0	$3.8	$10.7
Total	**$432.3**	**$0.0**	**$300.0**	**$732.3**	**$296.4**	**$0.0**	**$208.1**	**$504.5**

a. Initial one-time cost (other than capital technology costs), if applicable, consist of a one-time cost to close bottom ash system.

Source: U.S. EPA Analysis, 2015.

B.2 Costs and Economic Impacts Screening Analyses

B.2.1 Plant-Level Analysis

Table B-4 reports plant-level cost-to-revenue results by owner type and regulatory option. EPA estimates that for the majority of steam electric power plants, including those expected to incur zero compliance costs, costs would not exceed the 1 percent of revenue threshold under any of the five regulatory options. Ninety-three percent of plants have costs less than 1 percent of revenue under the final ELGs (Option D).

Table B-4: Plant-Level Cost-to-Revenue Analysis Results by Owner Type and Regulatory Option for Scenario without CPP [a]

Owner Type	Total Number of Plants	Number of Plants with a Ratio of			
		0% [b]	≠0 and <1%	≥1 and <3%	≥3%
Option A					
Cooperative	63	54	7	2	0
Federal	15	10	3	2	0
Investor-owned	681	609	69	3	0
Municipality	122	113	5	3	1
Nonutility	153	150	3	0	0
Other Political Subdivision	41	41	0	0	0
State	5	3	2	0	0
Total	**1,080**	**980**	**89**	**10**	**1**
Option B					
Cooperative	63	54	5	4	0
Federal	15	10	2	3	0
Investor-owned	681	609	68	3	1
Municipality	122	113	4	2	3
Nonutility	153	150	3	0	0
Other Political Subdivision	41	41	0	0	0
State	5	3	2	0	0
Total	**1,080**	**980**	**84**	**12**	**4**
Option C					
Cooperative	63	51	5	7	0
Federal	15	10	2	3	0
Investor-owned	681	575	95	9	2
Municipality	122	112	3	4	3
Nonutility	153	149	4	0	0
Other Political Subdivision	41	41	0	0	0
State	5	3	1	1	0
Total	**1,080**	**941**	**110**	**24**	**5**
Option D					
Cooperative	63	47	6	8	2
Federal	15	10	2	3	0
Investor-owned	681	554	94	31	2
Municipality	122	102	4	6	10
Nonutility	153	144	4	5	0
Other Political Subdivision	41	39	0	0	2
State	5	3	0	1	1
Total	**1,080**	**899**	**110**	**54**	**17**
Option E					
Cooperative	63	47	5	9	2
Federal	15	10	2	3	0
Investor-owned	681	544	95	40	2
Municipality	122	100	6	5	11
Nonutility	153	143	5	5	0
Other Political Subdivision	41	38	1	0	2
State	5	3	0	1	1
Total	**1,080**	**885**	**114**	**63**	**18**

a. Plant counts are weighted estimates.

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

Source: U.S. EPA Analysis, 2015.

B.2.2 Entity-Level Analysis

EPA estimates that 243 and 507 parent entities own steam electric power plants under Case 1 and Case 2, respectively. EPA estimates that under Case 1, the majority of parent entities would incur annualized costs of less than 1 percent of revenues under all five regulatory options; 87 percent of entities have annualized costs less than 1 percent of revenue under the final ELGs (Option D) for the scenario without CPP.[122] Case 2 shows the same number of entities with cost-to-revenue ratios greater than zero; 91 percent of entities have costs less than 1 percent of revenue ranges under the final ELGs (Option D) for the scenario without CPP.

Table B-5: Entity-Level Cost-to-Revenue Analysis Results, for Scenario Without CPP

	Case 1: Lower bound estimate of number of entities owning steam electric power plants						Case 2: Upper bound estimate of number of entities owning steam electric power plants					
	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[b]**		**0%[a]**	**≠0 and <1%**	**≥1 and <3%**	**≥3%**	**Unknown[b]**
Option A												
Cooperative	29	19	9	0	0	1	49	36	9	0	0	3
Federal	2	0	1	0	0	1	4	2	1	0	0	1
Investor-owned	97	64	29	0	1	3	244	204	29	0	1	10
Municipality	65	56	6	2	1	0	101	92	6	2	1	0
Nonutility	36	26	2	0	0	8	77	62	2	0	0	13
Other Political Subdivision	12	11	0	0	0	1	30	27	0	0	0	3
State	2	1	1	0	0	0	2	1	1	0	0	0
Total	**243**	**177**	**48**	**2**	**2**	**14**	**507**	**425**	**48**	**2**	**2**	**30**
Option B												
Cooperative	29	19	9	0	0	1	49	36	9	0	0	3
Federal	2	0	1	0	0	1	4	2	1	0	0	1
Investor-owned	97	64	29	0	1	3	244	204	29	0	1	10
Municipality	65	56	4	4	1	0	101	92	4	4	1	0
Nonutility	36	26	2	0	0	8	77	62	2	0	0	13
Other Political Subdivision	12	11	0	0	0	1	30	27	0	0	0	3
State	2	1	1	0	0	0	2	1	1	0	0	0
Total	**243**	**177**	**46**	**4**	**2**	**14**	**507**	**425**	**46**	**4**	**2**	**30**

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

Table B-5: Entity-Level Cost-to-Revenue Analysis Results, for Scenario Without CPP

Entity Type	Case 1: Lower bound estimate of number of entities owning steam electric power plants						Case 2: Upper bound estimate of number of entities owning steam electric power plants					
	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[b]		0%[a]	≠0 and <1%	≥1 and <3%	≥3%	Unknown[b]
Option C												
Cooperative	29	15	13	0	0	1	49	32	13	0	0	3
Federal	2	0	1	0	0	1	4	2	1	0	0	1
Investor-owned	97	58	35	0	1	3	244	198	35	0	1	10
Municipality	65	55	4	4	2	0	101	91	4	4	2	0
Nonutility	36	25	3	0	0	8	77	61	3	0	0	13
Other Political Subdivision	12	11	0	0	0	1	30	27	0	0	0	3
State	2	1	0	1	0	0	2	1	0	1	0	0
Total	**243**	**165**	**56**	**5**	**3**	**14**	**507**	**413**	**56**	**5**	**3**	**30**
Option D												
Cooperative	29	13	14	1	0	1	49	30	14	1	0	3
Federal	2	0	1	0	0	1	4	2	1	0	0	1
Investor-owned	97	57	35	1	1	3	244	197	35	1	1	10
Municipality	65	46	8	7	4	0	101	82	8	7	4	0
Nonutility	36	23	3	2	0	8	77	59	3	2	0	13
Other Political Subdivision	12	9	2	0	0	1	30	25	2	0	0	3
State	2	1	0	1	0	0	2	1	0	1	0	0
Total	**243**	**149**	**63**	**12**	**5**	**14**	**507**	**397**	**63**	**12**	**5**	**30**
Option E												
Cooperative	29	13	12	3	0	1	49	30	12	3	0	3
Federal	2	0	1	0	0	1	4	2	1	0	0	1
Investor-owned	97	54	38	1	1	3	244	194	38	1	1	10
Municipality	65	45	7	8	5	0	101	81	7	8	5	0
Nonutility	36	23	3	2	0	8	77	59	3	2	0	13
Other Political Subdivision	12	9	2	0	0	1	30	25	2	0	0	3
State	2	1	0	1	0	0	2	1	0	1	0	0
Total	**243**	**145**	**63**	**15**	**6**	**14**	**507**	**393**	**63**	**15**	**6**	**30**

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

b. EPA was unable to determine revenues for 14 and 30 parent entities under Case 1 and Case 2, respectively.
Source: U.S. EPA Analysis, 2015.

B.3 Assessment of Potential Electricity Price Effects

B.3.1 Impacts on Electricity Prices

As reported in *Table B-6* annualized compliance costs (in cents per KWh sales) are zero in ASCC and HICC regions for all options. The costs per unit of sale are highest in the SERC and RFC regions for all five options analyzed. On average, across the United States, Option A results in the lowest cost of 0.004¢ per KWh, while

Option E results in the highest cost of 0.019¢ per KWh. The final BAT and PSES (Option D) result in national costs of 0.018¢ per KWh.

Table B-6: Compliance Cost per KWh Sales by NERC Region and Regulatory Option in 2015 for Scenario without CPP ($2013)[a]

NERC Region	Total Electricity Sales (at 2015; MWh)	Annualized Pre-Tax Compliance Costs (at 2015; $2013)	Costs per Unit of Sales (2013¢/KWh Sales)
Option A			
ASCC	6,288,931	$0	¢0.000
FRCC	210,529,236	$1,521,391	¢0.001
HICC	9,639,157	$0	¢0.000
MRO	208,620,000	$2,536,724	¢0.001
NPCC	260,550,000	$231,073	¢0.000
RFC	866,450,000	$36,878,378	¢0.004
SERC	1,009,880,000	$96,563,904	¢0.010
SPP	196,820,000	$1,928,791	¢0.001
TRE	313,222,656	$2,069,946	¢0.001
WECC	670,710,000	$979,602	¢0.000
U.S.	**3,752,709,980**	**$142,709,808**	**¢0.004**
Option B			
ASCC	6,288,931	$0	¢0.000
FRCC	210,529,236	$9,881,915	¢0.005
HICC	9,639,157	$0	¢0.000
MRO	208,620,000	$3,942,115	¢0.002
NPCC	260,550,000	$1,185,108	¢0.000
RFC	866,450,000	$78,028,304	¢0.009
SERC	1,009,880,000	$143,085,577	¢0.014
SPP	196,820,000	$4,215,839	¢0.002
TRE	313,222,656	$3,829,861	¢0.001
WECC	670,710,000	$1,604,401	¢0.000
U.S.	**3,752,709,980**	**$245,773,120**	**¢0.007**
Option C			
ASCC	6,288,931	$0	¢0.000
FRCC	210,529,236	$9,881,915	¢0.005
HICC	9,639,157	$0	¢0.000
MRO	208,620,000	$13,168,894	¢0.006
NPCC	260,550,000	$1,185,108	¢0.000
RFC	866,450,000	$203,342,222	¢0.023
SERC	1,009,880,000	$218,113,730	¢0.022
SPP	196,820,000	$23,103,852	¢0.012
TRE	313,222,656	$12,784,547	¢0.004
WECC	670,710,000	$4,037,919	¢0.001
U.S.	**3,752,709,980**	**$485,618,186**	**¢0.013**

Table B-6: Compliance Cost per KWh Sales by NERC Region and Regulatory Option in 2015 for Scenario without CPP ($2013)[a]

NERC Region	Total Electricity Sales (at 2015; MWh)	Annualized Pre-Tax Compliance Costs (at 2015; $2013)	Costs per Unit of Sales (2013¢/KWh Sales)
Option D			
ASCC	6,288,931	$0	¢0.000
FRCC	210,529,236	$9,881,915	¢0.005
HICC	9,639,157	$0	¢0.000
MRO	208,620,000	$35,871,050	¢0.017
NPCC	260,550,000	$12,286,833	¢0.005
RFC	866,450,000	$260,679,379	¢0.030
SERC	1,009,880,000	$273,732,927	¢0.027
SPP	196,820,000	$38,591,660	¢0.020
TRE	313,222,656	$12,784,547	¢0.004
WECC	670,710,000	$14,860,526	¢0.002
U.S.	**3,752,709,980**	**$658,688,836**	**¢0.018**
Option E			
ASCC	6,288,931	$0	¢0.000
FRCC	210,529,236	$12,228,882	¢0.006
HICC	9,639,157	$0	¢0.000
MRO	208,620,000	$41,942,965	¢0.020
NPCC	260,550,000	$14,393,668	¢0.006
RFC	866,450,000	$296,934,023	¢0.034
SERC	1,009,880,000	$289,622,503	¢0.029
SPP	196,820,000	$44,956,945	¢0.023
TRE	313,222,656	$16,671,453	¢0.005
WECC	670,710,000	$15,543,076	¢0.002
U.S.	**3,752,709,980**	**$732,293,515**	**¢0.020**

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

Source: U.S. EPA Analysis, 2015; U.S. DOE 2014a; U.S. DOE 2012d.

To determine the relative significance of compliance costs on electricity prices across consumer groups, EPA compared the per KWh compliance cost to baseline retail electricity prices by consuming group, and for the average of the groups. As reported in *Table B-7* for the scenario without CPP, across the United States, Option A is estimated to result in the smallest electricity price increase relative to baseline electricity prices, 0.04 percent, while Option E is estimated to yield the largest increase of approximately 0.21 percent. The final BAT and PSES (Option D) are estimated to result in an approximate 0.19 percent increase in electricity prices.

Looking across the four consumer groups and assuming that any price increase would apply equally to all consumer groups, industrial consumers are estimated to experience the highest price increases relative to their baseline electricity price, while residential consumers are estimated to experience the lowest price increases, again relative to their baseline electricity price. For Option D and the scenario without CPP, the 0.018 ¢/KWh represents 0.28 percent of the baseline electricity price for industrial consumers, and 0.15 percent of that for residential consumers. The higher relative price increase for industrial consumers is due to the lower baseline electricity rates paid by industrial consumers and EPA's assumption of uniform increase across all consumer groups; it does not reflect differential distribution of the incremental costs across consumer groups.

Table B-7: Projected 2015 Price (Cents per KWh of Sales) and Potential Price Increase Due to Compliance Costs by NERC Region and Regulatory Option, for Scenario Without CPP ($2013)[a]

NERC Region	Compliance Cost (¢/KWh)	Residential		Commercial		Industrial		Transportation		All Sector Average	
		Baseline Price	% Change	Baseline Price	% Change	Baseline Price	% Change	Baseline Price	% Change	Baseline Price	% Change
Option A											
ASCC	¢0.000	17.58	0.00%	17.58	0.00%	17.58	0.00%	17.58	0.00%	17.58	0.00%
FRCC	¢0.001	11.24	0.01%	9.25	0.01%	8.04	0.01%	8.96	0.01%	10.16	0.01%
HICC	¢0.000	37.90	0.00%	37.90	0.00%	37.90	0.00%	37.90	0.00%	37.90	0.00%
MRO	¢0.001	10.52	0.01%	8.11	0.01%	5.94	0.02%	7.77	0.02%	8.06	0.02%
NPCC	¢0.000	18.10	0.00%	13.69	0.00%	8.87	0.00%	13.48	0.00%	14.51	0.00%
RFC	¢0.004	12.59	0.03%	10.40	0.04%	6.75	0.06%	9.96	0.04%	10.03	0.04%
SERC	¢0.010	10.20	0.09%	8.78	0.11%	5.79	0.17%	8.21	0.12%	8.39	0.11%
SPP	¢0.001	9.47	0.01%	7.89	0.01%	5.59	0.02%	7.68	0.01%	7.78	0.01%
TRE	¢0.001	10.82	0.01%	6.84	0.01%	5.12	0.01%	8.51	0.01%	7.89	0.01%
WECC	¢0.000	12.08	0.00%	10.99	0.00%	6.95	0.00%	10.14	0.00%	10.38	0.00%
US	**¢0.004**	**11.65**	**0.03%**	**9.77**	**0.04%**	**6.30**	**0.06%**	**10.51**	**0.04%**	**9.48**	**0.04%**
Option B											
ASCC	¢0.000	17.58	0.00%	17.58	0.00%	17.58	0.00%	17.58	0.00%	17.58	0.00%
FRCC	¢0.005	11.24	0.04%	9.25	0.05%	8.04	0.06%	8.96	0.05%	10.16	0.05%
HICC	¢0.000	37.90	0.00%	37.90	0.00%	37.90	0.00%	37.90	0.00%	37.90	0.00%
MRO	¢0.002	10.52	0.02%	8.11	0.02%	5.94	0.03%	7.77	0.02%	8.06	0.02%
NPCC	¢0.000	18.10	0.00%	13.69	0.00%	8.87	0.01%	13.48	0.00%	14.51	0.00%
RFC	¢0.009	12.59	0.07%	10.40	0.09%	6.75	0.13%	9.96	0.09%	10.03	0.09%
SERC	¢0.014	10.20	0.14%	8.78	0.16%	5.79	0.24%	8.21	0.17%	8.39	0.17%
SPP	¢0.002	9.47	0.02%	7.89	0.03%	5.59	0.04%	7.68	0.03%	7.78	0.03%
TRE	¢0.001	10.82	0.01%	6.84	0.02%	5.12	0.02%	8.51	0.01%	7.89	0.02%
WECC	¢0.000	12.08	0.00%	10.99	0.00%	6.95	0.00%	10.14	0.00%	10.38	0.00%
US	**¢0.007**	**11.65**	**0.06%**	**9.77**	**0.07%**	**6.30**	**0.10%**	**10.51**	**0.06%**	**9.48**	**0.07%**
Option C											
ASCC	¢0.000	17.58	0.00%	17.58	0.00%	17.58	0.00%	17.58	0.00%	17.58	0.00%
FRCC	¢0.005	11.24	0.04%	9.25	0.05%	8.04	0.06%	8.96	0.05%	10.16	0.05%
HICC	¢0.000	37.90	0.00%	37.90	0.00%	37.90	0.00%	37.90	0.00%	37.90	0.00%
MRO	¢0.006	10.52	0.06%	8.11	0.08%	5.94	0.11%	7.77	0.08%	8.06	0.08%
NPCC	¢0.000	18.10	0.00%	13.69	0.00%	8.87	0.01%	13.48	0.00%	14.51	0.00%
RFC	¢0.023	12.59	0.19%	10.40	0.23%	6.75	0.35%	9.96	0.24%	10.03	0.23%
SERC	¢0.022	10.20	0.21%	8.78	0.25%	5.79	0.37%	8.21	0.26%	8.39	0.26%
SPP	¢0.012	9.47	0.12%	7.89	0.15%	5.59	0.21%	7.68	0.15%	7.78	0.15%
TRE	¢0.004	10.82	0.04%	6.84	0.06%	5.12	0.08%	8.51	0.05%	7.89	0.05%
WECC	¢0.001	12.08	0.00%	10.99	0.01%	6.95	0.01%	10.14	0.01%	10.38	0.01%
US	**¢0.013**	**11.65**	**0.11%**	**9.77**	**0.13%**	**6.30**	**0.21%**	**10.51**	**0.12%**	**9.48**	**0.14%**

Table B-7: Projected 2015 Price (Cents per KWh of Sales) and Potential Price Increase Due to Compliance Costs by NERC Region and Regulatory Option, for Scenario Without CPP ($2013)[a]

NERC Region	Compliance Cost (¢/KWh)	Residential		Commercial		Industrial		Transportation		All Sector Average	
		Baseline Price	% Change	Baseline Price	% Change	Baseline Price	% Change	Baseline Price	% Change	Baseline Price	% Change
Option D											
ASCC	¢0.000	17.58	0.00%	17.58	0.00%	17.58	0.00%	17.58	0.00%	17.58	0.00%
FRCC	¢0.005	11.24	0.04%	9.25	0.05%	8.04	0.06%	8.96	0.05%	10.16	0.05%
HICC	¢0.000	37.90	0.00%	37.90	0.00%	37.90	0.00%	37.90	0.00%	37.90	0.00%
MRO	¢0.017	10.52	0.16%	8.11	0.21%	5.94	0.29%	7.77	0.22%	8.06	0.21%
NPCC	¢0.005	18.10	0.03%	13.69	0.03%	8.87	0.05%	13.48	0.03%	14.51	0.03%
RFC	¢0.030	12.59	0.24%	10.40	0.29%	6.75	0.45%	9.96	0.30%	10.03	0.30%
SERC	¢0.027	10.20	0.27%	8.78	0.31%	5.79	0.47%	8.21	0.33%	8.39	0.32%
SPP	¢0.020	9.47	0.21%	7.89	0.25%	5.59	0.35%	7.68	0.26%	7.78	0.25%
TRE	¢0.004	10.82	0.04%	6.84	0.06%	5.12	0.08%	8.51	0.05%	7.89	0.05%
WECC	¢0.002	12.08	0.02%	10.99	0.02%	6.95	0.03%	10.14	0.02%	10.38	0.02%
US	**¢0.018**	**11.65**	**0.15%**	**9.77**	**0.18%**	**6.30**	**0.28%**	**10.51**	**0.17%**	**9.48**	**0.19%**
Option E											
ASCC	¢0.000	17.58	0.00%	17.58	0.00%	17.58	0.00%	17.58	0.00%	17.58	0.00%
FRCC	¢0.006	11.24	0.05%	9.25	0.06%	8.04	0.07%	8.96	0.06%	10.16	0.06%
HICC	¢0.000	37.90	0.00%	37.90	0.00%	37.90	0.00%	37.90	0.00%	37.90	0.00%
MRO	¢0.020	10.52	0.19%	8.11	0.25%	5.94	0.34%	7.77	0.26%	8.06	0.25%
NPCC	¢0.006	18.10	0.03%	13.69	0.04%	8.87	0.06%	13.48	0.04%	14.51	0.04%
RFC	¢0.034	12.59	0.27%	10.40	0.33%	6.75	0.51%	9.96	0.34%	10.03	0.34%
SERC	¢0.029	10.20	0.28%	8.78	0.33%	5.79	0.50%	8.21	0.35%	8.39	0.34%
SPP	¢0.023	9.47	0.24%	7.89	0.29%	5.59	0.41%	7.68	0.30%	7.78	0.29%
TRE	¢0.005	10.82	0.05%	6.84	0.08%	5.12	0.10%	8.51	0.06%	7.89	0.07%
WECC	¢0.002	12.08	0.02%	10.99	0.02%	6.95	0.03%	10.14	0.02%	10.38	0.02%
US	**¢0.020**	**11.65**	**0.17%**	**9.77**	**0.20%**	**6.30**	**0.31%**	**10.51**	**0.19%**	**9.48**	**0.21%**

a. The rate impact analysis assumes full pass-through of all compliance costs to electricity consumers.
Sources: U.S. EPA Analysis, 2015; U.S. DOE, 2014a; U.S. DOE, 2012d.

B.3.2 Impacts on Household Electricity Costs

Table B-8 reports the results of the analysis by NERC region for each option, and overall for the United States for the scenario without CPP.

Average annual cost per residential household is zero in ASCC and HICC for all options. The average annual cost per residential household is generally highest in SERC, while regions facing the lowest non-zero cost vary (WECC and/or NPCC, depending on the option). In particular for the final BAT and PSES (Option D) under the scenario without CPP, results show the average annual cost per residential household increasing by $0.20 to $3.67 depending on the region (and excluding ASCC and HICC regions), with a national average of $1.86.

Table B-8: Average Annual Cost per Household in 2015 by NERC Region and Regulatory Option for Scenario Without CPP ($2013)[a]

NERC Region	Total Annual Compliance Cost (at 2015; $2013)	Total Electricity Sales (at 2014; MWh)	Compliance Cost per Unit of Sales ($2013/MWh)	Residential Electricity Sales (at 2015; MWh)	Number of Households (at 2015)	Residential Sales per Residential Consumer (MWh)	Compliance Cost per Household ($2013)
Option A							
ASCC	$0	6,288,931	$0.00	2,117,367	267,167	7.93	$0.00
FRCC	$1,521,391	210,529,236	$0.01	105,233,155	8,121,801	12.96	$0.09
HICC	$0	9,639,157	$0.00	2,739,298	419,612	6.53	$0.00
MRO	$2,536,724	208,620,000	$0.01	56,124,684	5,530,600	10.15	$0.12
NPCC	$231,073	260,550,000	$0.00	102,150,404	13,620,886	7.50	$0.01
RFC	$36,878,378	866,450,000	$0.04	337,291,906	33,594,289	10.04	$0.43
SERC	$96,563,904	1,009,880,000	$0.10	351,008,786	25,921,554	13.54	$1.29
SPP	$1,928,791	196,820,000	$0.01	69,196,041	5,373,947	12.88	$0.13
TRE	$2,069,946	313,222,656	$0.01	68,217,998	4,976,747	13.71	$0.09
WECC	$979,602	670,710,000	$0.00	239,135,284	26,736,937	8.94	$0.01
U.S.	**$142,709,808**	**3,752,709,980**	**$0.04**	**1,333,214,923**	**124,563,540**	**10.70**	**$0.41**
Option B							
ASCC	$0	6,288,931	$0.00	2,117,367	267,167	7.93	$0.00
FRCC	$9,881,915	210,529,236	$0.05	105,233,155	8,121,801	12.96	$0.61
HICC	$0	9,639,157	$0.00	2,739,298	419,612	6.53	$0.00
MRO	$3,942,115	208,620,000	$0.02	56,124,684	5,530,600	10.15	$0.19
NPCC	$1,185,108	260,550,000	$0.00	102,150,404	13,620,886	7.50	$0.03
RFC	$78,028,304	866,450,000	$0.09	337,291,906	33,594,289	10.04	$0.90
SERC	$143,085,577	1,009,880,000	$0.14	351,008,786	25,921,554	13.54	$1.92
SPP	$4,215,839	196,820,000	$0.02	69,196,041	5,373,947	12.88	$0.28
TRE	$3,829,861	313,222,656	$0.01	68,217,998	4,976,747	13.71	$0.17
WECC	$1,604,401	670,710,000	$0.00	239,135,284	26,736,937	8.94	$0.02
U.S.	**$245,773,120**	**3,752,709,980**	**$0.07**	**1,333,214,923**	**124,563,540**	**10.70**	**$0.70**
Option C							
ASCC	$0	6,288,931	$0.00	2,117,367	267,167	7.93	$0.00
FRCC	$9,881,915	210,529,236	$0.05	105,233,155	8,121,801	12.96	$0.61
HICC	$0	9,639,157	$0.00	2,739,298	419,612	6.53	$0.00
MRO	$13,168,894	208,620,000	$0.06	56,124,684	5,530,600	10.15	$0.64
NPCC	$1,185,108	260,550,000	$0.00	102,150,404	13,620,886	7.50	$0.03
RFC	$203,342,222	866,450,000	$0.23	337,291,906	33,594,289	10.04	$2.36
SERC	$218,113,730	1,009,880,000	$0.22	351,008,786	25,921,554	13.54	$2.92
SPP	$23,103,852	196,820,000	$0.12	69,196,041	5,373,947	12.88	$1.51
TRE	$12,784,547	313,222,656	$0.04	68,217,998	4,976,747	13.71	$0.56
WECC	$4,037,919	670,710,000	$0.01	239,135,284	26,736,937	8.94	$0.05
U.S.	**$485,618,186**	**3,752,709,980**	**$0.13**	**1,333,214,923**	**124,563,540**	**10.70**	**$1.39**

Table B-8: Average Annual Cost per Household in 2015 by NERC Region and Regulatory Option for Scenario Without CPP ($2013)[a]

NERC Region	Total Annual Compliance Cost (at 2015; $2013)	Total Electricity Sales (at 2014; MWh)	Compliance Cost per Unit of Sales ($2013/MWh)	Residential Electricity Sales (at 2015; MWh)	Number of Households (at 2015)	Residential Sales per Residential Consumer (MWh)	Compliance Cost per Household ($2013)
Option D							
ASCC	$0	6,288,931	$0.00	2,117,367	267,167	7.93	$0.00
FRCC	$9,881,915	210,529,236	$0.05	105,233,155	8,121,801	12.96	$0.61
HICC	$0	9,639,157	$0.00	2,739,298	419,612	6.53	$0.00
MRO	$35,871,050	208,620,000	$0.17	56,124,684	5,530,600	10.15	$1.74
NPCC	$12,286,833	260,550,000	$0.05	102,150,404	13,620,886	7.50	$0.35
RFC	$260,679,379	866,450,000	$0.30	337,291,906	33,594,289	10.04	$3.02
SERC	$273,732,927	1,009,880,000	$0.27	351,008,786	25,921,554	13.54	$3.67
SPP	$38,591,660	196,820,000	$0.20	69,196,041	5,373,947	12.88	$2.52
TRE	$12,784,547	313,222,656	$0.04	68,217,998	4,976,747	13.71	$0.56
WECC	$14,860,526	670,710,000	$0.02	239,135,284	26,736,937	8.94	$0.20
U.S.	**$658,688,836**	**3,752,709,980**	**$0.18**	**1,333,214,923**	**124,563,540**	**10.70**	**$1.88**
Option E							
ASCC	$0	6,288,931	$0.00	2,117,367	267,167	7.93	$0.00
FRCC	$12,228,882	210,529,236	$0.06	105,233,155	8,121,801	12.96	$0.75
HICC	$0	9,639,157	$0.00	2,739,298	419,612	6.53	$0.00
MRO	$41,942,965	208,620,000	$0.20	56,124,684	5,530,600	10.15	$2.04
NPCC	$14,393,668	260,550,000	$0.06	102,150,404	13,620,886	7.50	$0.41
RFC	$296,934,023	866,450,000	$0.34	337,291,906	33,594,289	10.04	$3.44
SERC	$289,622,503	1,009,880,000	$0.29	351,008,786	25,921,554	13.54	$3.88
SPP	$44,956,945	196,820,000	$0.23	69,196,041	5,373,947	12.88	$2.94
TRE	$16,671,453	313,222,656	$0.05	68,217,998	4,976,747	13.71	$0.73
WECC	$15,543,076	670,710,000	$0.02	239,135,284	26,736,937	8.94	$0.21
U.S.	**$732,293,515**	**3,752,709,980**	**$0.20**	**1,333,214,923**	**124,563,540**	**10.70**	**$2.09**

a. The rate impact analysis assumes full pass-through of all compliance costs to electricity consumers.
Sources: U.S. EPA Analysis, 2015; U.S. DOE, 2014a; U.S. DOE, 2012d.

B.3.3 Distribution of Electricity Cost Impact on Household

Table B-9 shows the distribution for the overall United States and for the five states with the largest post-compliance increases in household annual electricity expenditures for the scenario without CPP. Overall, the results (particularly when considering impacts relative to income) show that the *final rule is not distributionally neutral* and that impacts are most significant, in relative term, for households in the lower income categories, *i.e.*, relative impacts are not uniform across the income ranges. The largest impact on any household group occurs in West Virginia where the increase in electricity price represents 0.44 percent of the adjusted household income of households in the “Less than $5,000” income range, whereas the relative impact for households in the “$70,000 or more” range is approximately 0.02 percent. The results for the United States as a whole show impacts that are more uniform across the income ranges, than those for the top 5 states. Other states fall in between these results along the gradient of neutral to skewed distribution.

Table B-9: Electricity Price Increase for Option D Relative to: (1) After-tax Income, (2) Baseline Energy Expenditure and (3) Baseline Housing Expenditure, by Household Income Range for Top 5 States with the Highest Post-compliance Increases in Household Annual Electricity Expenditures

Item	All consumer units	Less than $5,000	$5,000 to $9,999	$10,000 to $14,999	$15,000 to $19,999	$20,000 to $29,999	$30,000 to $39,999	$40,000 to $49,999	$50,000 to $69,999	$70,000 and more
(1) Electricity price increase relative to after-tax income (unadjusted)										
Indiana	0.01%	[a]	0.04%	0.03%	0.03%	0.02%	0.02%	0.01%	0.01%	0.01%
Kentucky	0.02%	0.89%	0.08%	0.06%	0.05%	0.04%	0.03%	0.02%	0.02%	0.01%
Missouri	0.01%	[a]	0.05%	0.03%	0.03%	0.02%	0.02%	0.01%	0.01%	0.01%
North Dakota	0.01%	[a]	0.04%	0.03%	0.03%	0.02%	0.02%	0.01%	0.01%	0.01%
West Virginia	0.04%	1.85%	0.18%	0.12%	0.10%	0.08%	0.06%	0.05%	0.04%	0.02%
U.S. Total	**0.00%**	**0.23%**	**0.01%**	**0.01%**	**0.01%**	**0.01%**	**0.01%**	**0.00%**	**0.00%**	**0.00%**
(2) Electricity price increase relative to after-tax income, adjusted for self-employment										
Indiana	0.01%	0.10%	0.04%	0.03%	0.03%	0.02%	0.02%	0.01%	0.01%	0.01%
Kentucky	0.02%	0.21%	0.09%	0.06%	0.05%	0.04%	0.03%	0.02%	0.02%	0.01%
Missouri	0.01%	0.11%	0.05%	0.03%	0.03%	0.02%	0.02%	0.01%	0.01%	0.01%
North Dakota	0.01%	0.10%	0.04%	0.03%	0.03%	0.02%	0.02%	0.01%	0.01%	0.01%
West Virginia	0.04%	0.44%	0.18%	0.12%	0.10%	0.08%	0.06%	0.05%	0.04%	0.02%
U.S. Total	**0.00%**	**0.04%**	**0.01%**	**0.01%**	**0.01%**	**0.01%**	**0.01%**	**0.00%**	**0.00%**	**0.00%**
(3) Electricity price increase relative to baseline energy expenditure										
Indiana	0.31%	0.33%	0.33%	0.32%	0.31%	0.32%	0.31%	0.31%	0.31%	0.30%
Kentucky	0.53%	0.54%	0.55%	0.55%	0.52%	0.53%	0.54%	0.54%	0.54%	0.50%
Missouri	0.33%	0.36%	0.36%	0.34%	0.34%	0.34%	0.33%	0.33%	0.33%	0.32%
North Dakota	0.31%	0.33%	0.33%	0.32%	0.31%	0.31%	0.31%	0.30%	0.31%	0.30%
West Virginia	1.10%	1.14%	1.15%	1.14%	1.09%	1.11%	1.14%	1.14%	1.14%	1.05%
U.S. Total	**0.09%**	**0.10%**	**0.10%**	**0.10%**	**0.10%**	**0.10%**	**0.10%**	**0.10%**	**0.09%**	**0.09%**
(4) Electricity price increase relative to baseline housing expenditure										
Indiana	0.04%	0.04%	0.05%	0.05%	0.05%	0.05%	0.05%	0.04%	0.04%	0.03%
Kentucky	0.07%	0.08%	0.10%	0.10%	0.09%	0.09%	0.08%	0.08%	0.07%	0.05%
Missouri	0.04%	0.04%	0.05%	0.05%	0.06%	0.05%	0.05%	0.04%	0.05%	0.03%
North Dakota	0.04%	0.04%	0.05%	0.05%	0.05%	0.05%	0.05%	0.04%	0.04%	0.03%
West Virginia	0.14%	0.17%	0.21%	0.21%	0.19%	0.18%	0.16%	0.16%	0.15%	0.11%
U.S. Total	**0.01%**	**0.01%**	**0.01%**	**0.01%**	**0.01%**	**0.01%**	**0.01%**	**0.01%**	**0.01%**	**0.01%**

[a] Average after-tax income is negative for this income group. The Bureau of Labor Statistics offers several possible reasons why income may be negative and/or expenditures may exceed income for the lower income groups. For example: "Consumer units whose members experience a spell of unemployment may draw on their savings to maintain their expenditures. Self-employed consumers may experience business losses that result in low or even negative incomes, but are able to maintain their expenditures by borrowing or relying on savings. Students may get by on loans while they are in school, and retirees may rely on savings and investments." (http://www.bls.gov/cex/faq.htm#q21)
Source: U.S. EPA Analysis, 2015.

EPA assesses the impact of electricity rate increases on affordability in two ways.

For the first analysis, EPA compared the post-compliance increase in electricity costs to pre-tax household income, for state and household-income ranges. When using the adjusted incomes across income groups, EPA found that none of household groups exceed the 1 percent threshold value (or the 2 percent threshold value). Looking at reported income groups and setting aside groups with negative incomes, only one household-income range in one state (households with pre-tax income less than $5,000 in West Virginia) exceeds the 1 percent threshold value and no household-income range in any state exceeds the 2 percent threshold value (see *Table B-10*). The results of this first analysis indicate that the incremental economic burden of the final rule on households is small.

For the second analysis, EPA compared the increase in total household energy costs to gross income. A review of the baseline energy burden, defined as the ratio of energy expenditures relative to gross (pre-tax) income, indicates that households in the lowest four income ranges (less than $5,000; $5,000 to $9,999; $10,000 to $14,999; $15,000 to $19,999) have baseline burdens that exceed the 6 percent threshold in all states and the District of Columbia (*Table B-11*). For the next lowest income range ($20,000 to $29,999), 39 states have households with baseline energy burdens exceeding the threshold. Households in all remaining four income ranges ($30,000 or higher) have baseline energy burden below the threshold in all areas. This observation holds whether one uses household incomes as reported in CES, or adjusted household incomes. When considering the effect of the final ELGs, by state and income range, EPA found that the post-compliance energy burden increases further for state-household groups that were already above the threshold in the baseline (35 and 31 states, depending on the income level), but the additional electricity costs due to the final rule do not push any *additional* state-household groups above the 6 percent threshold. The increase in burden for states-household groups already above the 6 percent energy burden threshold is very small. The maximum relative change occurs in West Virginia where households in the “Less than $5,000” range see their energy burden increase from 38.8 percent to 39.2 percent (0.4 percent change) (see *Table 7-7*). The results of this second analysis indicate that the final rule will increase energy costs for households with already high baseline energy burdens—absent any measure to mitigate the increase—but that increase is, again, small.

Table B-10: Number of Areas with Households Exceeding a 6-Percent Energy Burden Threshold, by Household Income Range

Item	Less than $5,000	$5,000 to $9,999	$10,000 to $14,999	$15,000 to $19,999	$20,000 to $29,999	$30,000 to $39,999	$40,000 to $49,999	$50,000 to $69,999	$70,000 and more
Number of states (and D.C.) exceeding threshold for energy burden in baseline	51	51	51	51	39	0	0	0	0
Number of states (and D.C.) with high baseline burden and increased electricity rates under Option D	35	35	35	35	31	0	0	0	0
Change in the number of states (and D.C.) that exceed the threshold for energy burden under Option D	0	0	0	0	0	0	0	0	0

Source: U.S. EPA Analysis, 2015.

Table B-11: Baseline and post-compliance energy burden (under Option D) by state and by household income range (states with non-zero ELG costs)

State	Period	All consumer units	Less than $5,000	$5,000 to $9,999	$10,000 to $14,999	$15,000 to $19,999	$20,000 to $29,999	$30,000 to $39,999	$40,000 to $49,999	$50,000 to $69,999	$70,000 and more
Alabama	Baseline	3.4%	38.8%	15.9%	11.1%	9.5%	7.1%	5.2%	4.4%	3.5%	2.0%
	Post-Compliance	3.4%	38.9%	15.9%	11.1%	9.5%	7.1%	5.3%	4.4%	3.5%	2.0%
Arkansas	Baseline	3.4%	38.8%	15.9%	11.1%	9.5%	7.1%	5.2%	4.4%	3.5%	2.0%
	Post-Compliance	3.4%	38.8%	15.9%	11.1%	9.5%	7.1%	5.3%	4.4%	3.5%	2.0%
Colorado	Baseline	2.5%	22.4%	11.9%	7.7%	6.3%	5.1%	4.1%	3.5%	2.8%	1.8%
	Post-Compliance	2.5%	22.4%	11.9%	7.7%	6.3%	5.1%	4.1%	3.5%	2.8%	1.8%
Connecticut	Baseline	3.3%	25.9%	13.3%	10.4%	8.6%	7.6%	5.9%	5.1%	4.1%	2.3%
	Post-Compliance	3.3%	25.9%	13.3%	10.4%	8.6%	7.6%	5.9%	5.1%	4.1%	2.3%
Florida	Baseline	3.4%	38.8%	15.9%	11.1%	9.5%	7.1%	5.2%	4.4%	3.5%	2.0%
	Post-Compliance	3.4%	38.8%	15.9%	11.1%	9.5%	7.1%	5.3%	4.4%	3.5%	2.0%
Georgia	Baseline	3.4%	38.8%	15.9%	11.1%	9.5%	7.1%	5.2%	4.4%	3.5%	2.0%
	Post-Compliance	3.4%	38.8%	15.9%	11.1%	9.5%	7.1%	5.3%	4.4%	3.5%	2.0%
Illinois	Baseline	3.1%	30.1%	13.6%	9.6%	8.8%	6.6%	5.3%	4.2%	3.6%	2.0%
	Post-Compliance	3.1%	30.2%	13.6%	9.6%	8.8%	6.6%	5.3%	4.3%	3.7%	2.0%
Indiana	Baseline	3.1%	30.1%	13.6%	9.6%	8.8%	6.6%	5.3%	4.2%	3.6%	2.0%
	Post-Compliance	3.1%	30.2%	13.6%	9.6%	8.8%	6.6%	5.3%	4.3%	3.7%	2.0%
Iowa	Baseline	3.1%	30.1%	13.6%	9.6%	8.8%	6.6%	5.3%	4.2%	3.6%	2.0%
	Post-Compliance	3.1%	30.2%	13.6%	9.6%	8.8%	6.6%	5.3%	4.3%	3.7%	2.0%
Kansas	Baseline	3.1%	30.1%	13.6%	9.6%	8.8%	6.6%	5.3%	4.2%	3.6%	2.0%
	Post-Compliance	3.1%	30.2%	13.6%	9.6%	8.8%	6.6%	5.3%	4.3%	3.7%	2.0%
Kentucky	Baseline	3.4%	38.8%	15.9%	11.1%	9.5%	7.1%	5.2%	4.4%	3.5%	2.0%
	Post-Compliance	3.4%	39.0%	15.9%	11.1%	9.5%	7.1%	5.3%	4.4%	3.5%	2.1%
Louisiana	Baseline	3.4%	38.8%	15.9%	11.1%	9.5%	7.1%	5.2%	4.4%	3.5%	2.0%
	Post-Compliance	3.4%	38.8%	15.9%	11.1%	9.5%	7.1%	5.3%	4.4%	3.5%	2.0%
Maryland	Baseline	3.4%	38.8%	15.9%	11.1%	9.5%	7.1%	5.2%	4.4%	3.5%	2.0%
	Post-Compliance	3.4%	38.8%	15.9%	11.1%	9.5%	7.1%	5.3%	4.4%	3.5%	2.0%
Massachusetts	Baseline	3.3%	25.9%	13.3%	10.4%	8.6%	7.6%	5.9%	5.1%	4.1%	2.3%
	Post-Compliance	3.3%	25.9%	13.3%	10.4%	8.6%	7.6%	5.9%	5.1%	4.1%	2.3%
Michigan	Baseline	3.1%	30.1%	13.6%	9.6%	8.8%	6.6%	5.3%	4.2%	3.6%	2.0%
	Post-Compliance	3.1%	30.2%	13.6%	9.6%	8.8%	6.6%	5.3%	4.3%	3.7%	2.0%
Minnesota	Baseline	3.1%	30.1%	13.6%	9.6%	8.8%	6.6%	5.3%	4.2%	3.6%	2.0%
	Post-Compliance	3.1%	30.1%	13.6%	9.6%	8.8%	6.6%	5.3%	4.2%	3.6%	2.0%
Mississippi	Baseline	3.4%	38.8%	15.9%	11.1%	9.5%	7.1%	5.2%	4.4%	3.5%	2.0%
	Post-Compliance	3.4%	38.8%	15.9%	11.1%	9.5%	7.1%	5.3%	4.4%	3.5%	2.0%
Missouri	Baseline	3.1%	30.1%	13.6%	9.6%	8.8%	6.6%	5.3%	4.2%	3.6%	2.0%
	Post-Compliance	3.1%	30.2%	13.6%	9.6%	8.8%	6.6%	5.3%	4.3%	3.7%	2.0%
Montana	Baseline	2.5%	22.4%	11.9%	7.7%	6.3%	5.1%	4.1%	3.5%	2.8%	1.8%
	Post-Compliance	2.5%	22.4%	11.9%	7.7%	6.3%	5.1%	4.1%	3.5%	2.8%	1.8%
Nebraska	Baseline	3.1%	30.1%	13.6%	9.6%	8.8%	6.6%	5.3%	4.2%	3.6%	2.0%
	Post-Compliance	3.1%	30.2%	13.6%	9.6%	8.8%	6.6%	5.3%	4.3%	3.7%	2.0%
New Hampshire	Baseline	3.3%	25.9%	13.3%	10.4%	8.6%	7.6%	5.9%	5.1%	4.1%	2.3%
	Post-Compliance	3.3%	25.9%	13.4%	10.4%	8.6%	7.6%	5.9%	5.1%	4.1%	2.3%
New Jersey	Baseline	3.3%	25.9%	13.3%	10.4%	8.6%	7.6%	5.9%	5.1%	4.1%	2.3%
	Post-Compliance	3.3%	25.9%	13.3%	10.4%	8.6%	7.6%	5.9%	5.1%	4.1%	2.3%
New York	Baseline	3.3%	25.9%	13.3%	10.4%	8.6%	7.6%	5.9%	5.1%	4.1%	2.3%
	Post-Compliance	3.3%	25.9%	13.3%	10.4%	8.6%	7.6%	5.9%	5.1%	4.1%	2.3%
North Carolina	Baseline	3.4%	38.8%	15.9%	11.1%	9.5%	7.1%	5.2%	4.4%	3.5%	2.0%
	Post-Compliance	3.4%	38.8%	15.9%	11.1%	9.5%	7.1%	5.3%	4.4%	3.5%	2.0%
North Dakota	Baseline	3.1%	30.1%	13.6%	9.6%	8.8%	6.6%	5.3%	4.2%	3.6%	2.0%
	Post-Compliance	3.1%	30.2%	13.6%	9.6%	8.8%	6.6%	5.3%	4.3%	3.7%	2.0%
Ohio	Baseline	3.1%	30.1%	13.6%	9.6%	8.8%	6.6%	5.3%	4.2%	3.6%	2.0%
	Post-Compliance	3.1%	30.2%	13.6%	9.6%	8.8%	6.6%	5.3%	4.2%	3.6%	2.0%

Table B-11: Baseline and post-compliance energy burden (under Option D) by state and by household income range (states with non-zero ELG costs)

State	Period	All consumer units	Less than $5,000	$5,000 to $9,999	$10,000 to $14,999	$15,000 to $19,999	$20,000 to $29,999	$30,000 to $39,999	$40,000 to $49,999	$50,000 to $69,999	$70,000 and more
Oklahoma	Baseline	3.4%	38.8%	15.9%	11.1%	9.5%	7.1%	5.2%	4.4%	3.5%	2.0%
	Post-Compliance	3.4%	38.8%	15.9%	11.1%	9.5%	7.1%	5.3%	4.4%	3.5%	2.0%
Pennsylvania	Baseline	3.3%	25.9%	13.3%	10.4%	8.6%	7.6%	5.9%	5.1%	4.1%	2.3%
	Post-Compliance	3.3%	25.9%	13.4%	10.4%	8.6%	7.6%	5.9%	5.1%	4.1%	2.3%
South Carolina	Baseline	3.4%	38.8%	15.9%	11.1%	9.5%	7.1%	5.2%	4.4%	3.5%	2.0%
	Post-Compliance	3.4%	38.9%	15.9%	11.1%	9.5%	7.1%	5.3%	4.4%	3.5%	2.0%
Tennessee	Baseline	3.4%	38.8%	15.9%	11.1%	9.5%	7.1%	5.2%	4.4%	3.5%	2.0%
	Post-Compliance	3.4%	38.9%	15.9%	11.1%	9.5%	7.1%	5.3%	4.4%	3.5%	2.0%
Texas	Baseline	3.4%	38.8%	15.9%	11.1%	9.5%	7.1%	5.2%	4.4%	3.5%	2.0%
	Post-Compliance	3.4%	38.8%	15.9%	11.1%	9.5%	7.1%	5.2%	4.4%	3.5%	2.0%
Virginia	Baseline	3.4%	38.8%	15.9%	11.1%	9.5%	7.1%	5.2%	4.4%	3.5%	2.0%
	Post-Compliance	3.4%	38.8%	15.9%	11.1%	9.5%	7.1%	5.3%	4.4%	3.5%	2.0%
Washington	Baseline	2.5%	22.4%	11.9%	7.7%	6.3%	5.1%	4.1%	3.5%	2.8%	1.8%
	Post-Compliance	2.5%	22.4%	11.9%	7.7%	6.3%	5.1%	4.1%	3.5%	2.8%	1.8%
West Virginia	Baseline	3.4%	38.8%	15.9%	11.1%	9.5%	7.1%	5.2%	4.4%	3.5%	2.0%
	Post-Compliance	3.4%	39.2%	16.0%	11.2%	9.6%	7.2%	5.3%	4.4%	3.5%	2.1%
Wisconsin	Baseline	3.1%	30.1%	13.6%	9.6%	8.8%	6.6%	5.3%	4.2%	3.6%	2.0%
	Post-Compliance	3.1%	30.2%	13.6%	9.6%	8.8%	6.6%	5.3%	4.2%	3.6%	2.0%
Wyoming	Baseline	2.5%	22.4%	11.9%	7.7%	6.3%	5.1%	4.1%	3.5%	2.8%	1.8%
	Post-Compliance	2.5%	22.5%	11.9%	7.8%	6.3%	5.1%	4.1%	3.5%	2.8%	1.8%
U.S. Total	**Baseline**	**3.2%**	**37.4%**	**14.2%**	**10.2%**	**8.8%**	**6.8%**	**5.2%**	**4.4%**	**3.6%**	**2.1%**
	Post-Compliance	**3.2%**	**37.4%**	**14.2%**	**10.2%**	**8.8%**	**6.8%**	**5.2%**	**4.4%**	**3.6%**	**2.1%**

Source: U.S. EPA Analysis, 2015.

These two analyses suggest that the incremental economic burden of the final rule 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 low income households to a greater extent than higher income households, the small impacts may be further moderated by existing pricing structures (see next section).

B.4 Assessment of Potential Impacts on Small Entities

Table B-12: Estimated Cost-To-Revenue Impact on Small Parent Entities, by Entity Type and Ownership Category for Scenario Without CPP[a,b]

Entity Type / Ownership Category	Case 1: Lower bound estimate of number of entities owning steam electric power plants (out of total of 110 small entities)				Case 2: Upper bound estimate of number of entities owning steam electric power plants (out of total of 191 small entities)			
	Cost ≥1% of Revenue		Cost ≥3% of Revenue		Cost ≥1% of Revenue		Cost ≥3% of Revenue	
	Number of Small Entities	% of Small Entities	Number of Small Entities	% of Small Entities	Number of Small Entities	% of Small Entities	Number of Small Entities	% of Small Entities
Option A								
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%
Municipality	1	2.8%	1	2.8%	1	2.3%	1	2.3%
Nonutility	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Other Political Subdivision	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Small Business[c]	***0***	***0.0%***	***0***	***0.0%***	***0***	***0.0%***	***0***	***0.0%***
Small Government[d]	***1***	***2.7%***	***1***	***2.7%***	***1***	***2.3%***	***1***	***2.3%***
Total	**1**	**0.9%**	**1**	**0.9%**	**1**	**0.5%**	**1**	**0.5%**
Option B								
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%
Municipality	3	8.3%	1	2.8%	3	7.0%	1	2.3%
Nonutility	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Other Political Subdivision	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Small Business[c]	***0***	***0.0%***	***0***	***0.0%***	***0***	***0.0%***	***0***	***0.0%***
Small Government[d]	***3***	***8.1%***	***1***	***2.7%***	***3***	***6.8%***	***1***	***2.3%***
Total	**3**	**2.7%**	**1**	**0.9%**	**3**	**1.6%**	**1**	**0.5%**
Option C								
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%
Municipality	4	11.1%	2	5.6%	4	9.4%	2	4.7%
Nonutility	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Other Political Subdivision	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Small Business[c]	***0***	***0.0%***	***0***	***0.0%***	***0***	***0.0%***	***0***	***0.0%***
Small Government[d]	***4***	***10.8%***	***2***	***5.4%***	***4***	***9.1%***	***2***	***4.6%***
Total	**4**	**3.6%**	**2**	**1.8%**	**4**	**2.1%**	**2**	**1.0%**

Table B-12: Estimated Cost-To-Revenue Impact on Small Parent Entities, by Entity Type and Ownership Category for Scenario Without CPP[a,b]

Entity Type / Ownership Category	Case 1: Lower bound estimate of number of entities owning steam electric power plants (out of total of 110 small entities)				Case 2: Upper bound estimate of number of entities owning steam electric power plants (out of total of 191 small entities)			
	Cost ≥1% of Revenue		Cost ≥3% of Revenue		Cost ≥1% of Revenue		Cost ≥3% of Revenue	
	Number of Small Entities	% of Small Entities	Number of Small Entities	% of Small Entities	Number of Small Entities	% of Small Entities	Number of Small Entities	% of Small Entities
Option D								
Cooperative	1	3.8%	0	0.0%	1	2.2%	0	0.0%
Investor-Owned	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Municipality	7	19.4%	3	8.3%	7	16.4%	3	7.0%
Nonutility	2	10.5%	0	0.0%	2	5.7%	0	0.0%
Other Political Subdivision	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Small Business[c]	***3***	***4.1%***	***0***	***0.0%***	***3***	***2.0%***	***0***	***0.0%***
Small Government[d]	***7***	***18.9%***	***3***	***8.1%***	***7***	***15.9%***	***3***	***6.8%***
Total	**10**	**9.1%**	**3**	**2.7%**	**10**	**5.2%**	**3**	**1.6%**
Option E								
Cooperative	3	11.5%	0	0.0%	3	6.5%	0	0.0%
Investor-Owned	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Municipality	7	19.4%	3	8.3%	7	16.4%	3	7.0%
Nonutility	2	10.5%	0	0.0%	2	5.7%	0	0.0%
Other Political Subdivision	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Small Business[c]	***5***	***6.9%***	***0***	***0.0%***	***5***	***3.4%***	***0***	***0.0%***
Small Government[d]	***7***	***18.9%***	***3***	***8.1%***	***7***	***16.0%***	***3***	***6.9%***
Total	**12**	**10.9%**	**3**	**2.7%**	**12**	**6.3%**	**3**	**1.6%**

a. The number of entities with cost-to-revenue impact of at least 3 percent is a subset of the number of entities with such ratios exceeding 1 percent.

b. Percentage values were calculated relative to the total of 110 (Case 1) and 191 (Case 2) small entities owning steam electric power plants regardless of whether these plants are expected to incur compliance technology costs under any of the regulatory options.

c. Small businesses include cooperatives, investor-owned utilities, and nonutilities.

d. Small governments include municipalities and other political subdivisions.
Source: U.S. EPA Analysis, 2015.

Table B-13: Estimated Cost-To-Revenue Impact on Small Parent Entities, by Entity Type and Ownership Category for Scenario With CPP[a,b]

Entity Type / Ownership Category	Case 1: Lower bound estimate of number of entities owning steam electric power plants (out of total of 110 small entities)				Case 2: Upper bound estimate of number of entities owning steam electric power plants (out of total of 191 small entities)			
	Cost ≥1% of Revenue		Cost ≥3% of Revenue		Cost ≥1% of Revenue		Cost ≥3% of Revenue	
	Number of Small Entities	% of Small Entities	Number of Small Entities	% of Small Entities	Number of Small Entities	% of Small Entities	Number of Small Entities	% of Small Entities
Option A								
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%
Municipality	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%
Other Political Subdivision	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Small Business[c]	***0***	***0.0%***	***0***	***0.0%***	***0***	***0.0%***	***0***	***0.0%***
Small Government[d]	***0***	***0.0%***	***0***	***0.0%***	***0***	***0.0%***	***0***	***0.0%***
Total	**0**	**0.0%**	**0**	**0.0%**	**0**	**0.0%**	**0**	**0.0%**
Option B								
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%
Municipality	1	2.8%	0	0.0%	1	2.3%	0	0.0%
Nonutility	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Other Political Subdivision	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Small Business[c]	***0***	***0.0%***	***0***	***0.0%***	***0***	***0.0%***	***0***	***0.0%***
Small Government[d]	***1***	***2.7%***	***0***	***0.0%***	***1***	***2.3%***	***0***	***0.0%***
Total	**1**	**0.9%**	**0**	**0.0%**	**1**	**0.5%**	**0**	**0.0%**
Option C								
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%
Municipality	2	5.6%	1	2.8%	2	4.7%	1	2.3%
Nonutility	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Other Political Subdivision	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Small Business[c]	***0***	***0.0%***	***0***	***0.0%***	***0***	***0.0%***	***0***	***0.0%***
Small Government[d]	***2***	***5.3%***	***1***	***2.6%***	***2***	***4.5%***	***1***	***2.2%***
Total	**2**	**1.8%**	**1**	**0.9%**	**2**	**1.0%**	**1**	**0.5%**
Option D								
Cooperative	1	3.8%	0	0.0%	1	2.2%	0	0.0%
Investor-Owned	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Municipality	4	11.1%	1	2.8%	4	9.4%	1	2.3%
Nonutility	1	5.3%	0	0.0%	1	2.8%	0	0.0%
Other Political Subdivision	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Small Business[c]	***2***	***2.7%***	***0***	***0.0%***	***2***	***1.4%***	***0***	***0.0%***
Small Government[d]	***4***	***10.5%***	***1***	***2.6%***	***4***	***9.0%***	***1***	***2.2%***
Total	**6**	**5.4%**	**1**	**0.9%**	**6**	**3.1%**	**1**	**0.5%**

Table B-13: Estimated Cost-To-Revenue Impact on Small Parent Entities, by Entity Type and Ownership Category for Scenario With CPP[a,b]

Entity Type / Ownership Category	Case 1: Lower bound estimate of number of entities owning steam electric power plants (out of total of 110 small entities)				Case 2: Upper bound estimate of number of entities owning steam electric power plants (out of total of 191 small entities)			
	Cost ≥1% of Revenue		Cost ≥3% of Revenue		Cost ≥1% of Revenue		Cost ≥3% of Revenue	
	Number of Small Entities	% of Small Entities	Number of Small Entities	% of Small Entities	Number of Small Entities	% of Small Entities	Number of Small Entities	% of Small Entities
Option E								
Cooperative	2	7.7%	0	0.0%	2	4.4%	0	0.0%
Investor-Owned	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Municipality	4	11.1%	1	2.8%	4	9.4%	1	2.3%
Nonutility	1	5.3%	0	0.0%	1	2.8%	0	0.0%
Other Political Subdivision	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Small Business[c]	***3***	***4.1%***	***0***	***0.0%***	***3***	***2.0%***	***0***	***0.0%***
Small Government[d]	***4***	***10.5%***	***1***	***2.6%***	***4***	***9.0%***	***1***	***2.2%***
Total	**7**	**6.3%**	**1**	**0.9%**	**7**	**3.6%**	**1**	**0.5%**

a. The number of entities with cost-to-revenue impact of at least 3 percent is a subset of the number of entities with such ratios exceeding 1 percent.

b. Percentage values were calculated relative to the total of 110 (Case 1) and 191 (Case 2) small entities owning steam electric power plants regardless of whether these plants are expected to incur compliance technology costs under any of the regulatory options.

c. Small businesses include cooperatives, investor-owned utilities, and nonutilities.

d. Small governments include municipalities and other political subdivisions.
Source: U.S. EPA Analysis, 2015.

B.5 Assessment of Potential Impacts on Governments and the Private Sector

For the scenario without CPP, EPA estimates that the *maximum* cost *in any one year* for compliance with the regulatory options to government entities (excluding federal government) range from $61.4 million under Option A to $256.7 million under Option E.[123,124] The final BAT and PSES (Option D) have maximum costs in any given year to government entities of $244.0 million. The *maximum* cost *in any given year* to the private sector range from $410.5 million under Option A to $1,846.1 million under Option E. Option D has maximum costs in any given year to the private sector of $1,670.5 million.

B.5.1 UMRA Analysis of Impact on Government Entities

Table B-14 summarizes the number of State, local and Tribal government entities and the number of steam electric power plants they own.

[123] Maximum costs are costs incurred by the entire universe of steam electric plants in a given year of occurrence under a given regulatory option.

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

Table B-14: Government-Owned Steam Electric Power Plants and Their Parent Entities

Entity Type	Parent Entities[a]	Steam electric power plants[b]
Municipality	65	122
Other Political Subdivision	12	41
State	2	5
Tribal	0	0
Total	**79**	**168**

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 weighted estimates. See *TDD* for discussion on development of plant sample weights.

Source: U.S. EPA Analysis, 2015

As presented in *Table B-15*, government entities are projected to incur the lowest compliance costs under Option A and the highest compliance costs under Option E.

Under Option D and for the scenario without CPP (*Table B-15*), compliance costs for government entities are approximately $60.1 million in the aggregate, with an average of $0.4 million per plant. Municipalities account for the largest share of this cost (52 percent), followed by state government entities (38 percent) and other political subdivisions (10 percent). The average cost per plant to States is $4.5 million, compared to $0.3 million and $0.2 million for plants owned by municipalities and other political subdivisions, respectively. The maximum annualized compliance costs estimated to be incurred by any single government-owned plant is $12.7 million for a State-owned plant, $3.9 million for a municipal plant, and $4.2 million for plants owned by other political subdivisions. The average cost per MW of government-owned generating capacity is estimated to be $933 per MW, with the highest average unit cost incurred by States ($4,621 per MW) and the lowest average unit cost incurred by other political subdivisions ($247 per MW).

Table B-15: Compliance Costs to Government Entities Owning Steam electric power plants under Scenario without CPP (Millions; $2013)

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 A					
Municipality	122	$7.2	$209	$0.1	$2.6
Other Political Subdivision	41	$0.0	$0	$0.0	$0.0
State	5	$2.7	$554	$0.5	$2.6
Total	**168**	**$9.9**	**$153**	**$0.1**	**$2.6**
Option B					
Municipality	122	$13.5	$393	$0.1	$3.9
Other Political Subdivision	41	$0.0	$0	$0.0	$0.0
State	5	$5.9	$1,204	$1.2	$3.9
Total	**168**	**$19.4**	**$301**	**$0.1**	**$3.9**
Option C					
Municipality	122	$16.0	$465	$0.1	$3.9
Other Political Subdivision	41	$0.0	$0	$0.0	$0.0
State	5	$14.7	$3,001	$2.9	$12.7
Total	**168**	**$30.6**	**$475**	**$0.2**	**$12.7**

Table B-15: Compliance Costs to Government Entities Owning Steam electric power plants under Scenario without CPP (Millions; $2013)

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 D					
Municipality	122	$31.3	$912	$0.3	$3.9
Other Political Subdivision	41	$6.2	$247	$0.2	$4.2
State	5	$22.6	$4,629	$4.5	$12.7
Total	**168**	**$60.1**	**$933**	**$0.4**	**$12.7**
Option E					
Municipality	122	$36.5	$1,063	$0.3	$4.3
Other Political Subdivision	41	$6.9	$273	$0.2	$4.2
State	5	$22.6	$4,629	$4.5	$12.7
Total	**168**	**$66.0**	**$1,024**	**$0.4**	**$12.7**

a. Plant counts and cost values are weighted estimates. See *TDD* for discussion on the development of plant sample weights.

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, 2015.

B.5.2 UMRA Analysis of Impact on Small Governments

Out of 1,080 government-owned steam electric power plants, EPA identified 47 plants that are owned by 37 small government entities. These 41 plants constitute approximately 28 percent of all government-owned plants.[125]

Table B-16: 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	29	36	65	76	46	**122**
Other Political Subdivision	11	1	12	40	1	**41**
State	2	0	2	5	0	**5**
Total	**42**	**37**	**79**	**121**	**47**	**168**

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 weighted estimates. See *TDD* for discussion on development of plant sample weights.
Source: U.S. EPA Analysis, 2015.

As presented in *Table B-17*, compliance costs are the lowest and associated regulatory impacts are the smallest under Option A and the largest under Option E. Generally, compliance costs are lower for small

[125] Counts exclude federal government entities and steam electric plants they own.

governments compared to costs for large governments and to small private entities; this trend holds in the aggregate and on a per plant basis under all regulatory options.

For Option D under the scenario without CPP, total annualized compliance costs are approximately $9.8 million for small government entities, compared to $50.3 million for large government entities and $40.6 million for small private entities. EPA estimates that, under Option D, a small government entity would, on average, incur $0.2 million in compliance costs per plant (but no more than $3.3 million per plant) compared to $0.4 million per plant (but no more than $12.7 million per plant) for plants owned by large governments, and $0.2 million per plant (but no more than $5.1 million per plant) for those owned by small private entities. On a per MW of capacity basis, small government entities are projected to incur an average cost of $2,608 per MW under Option D, while for large government and small private entities unit costs are estimated to be $829 per MW and $573 per MW, respectively.

As discussed in the preceding paragraphs and presented in *Table B-17*, EPA estimates total costs to small government entities, in the aggregate, to be lower than costs to large government or small private entities, in the aggregate and on a per plant basis. On a per MW basis, small governments face costs that tend to be higher than large governments and private entities. However, the fact that the average compliance cost per MW of plant capacity owned by small governments tends to be higher compared to that for plants owned by large governments or by small private entities, only shows that, on average, plants owned by small governments tend to be smaller compared to those owned by large governments or small private entities and reflects economies of scale in control technologies costs.

Table B-17: Compliance Costs for Electric Generators by Ownership Type and Size for Scenario Without CPP ($2013)

Ownership Type	Entity Size	Number of Plants (weighted)[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)[d]
Option A						
Government (excl. federal)	Small	47	$2.1	$556	$0.05	$1.6
	Large	121	$7.8	$128	$0.06	$2.6
Private	Small	185	$6.6	$94	$0.04	$1.9
	Large	713	$90.9	$156	$0.13	$8.8
All Plants		**1,080**	**$137.1**	**$184**	**$0.13**	**$17.7**
Option B						
Government (excl. federal)	Small	47	$3.8	$996	$0.09	$2.3
	Large	121	$15.6	$257	$0.13	$3.9
Private	Small	185	$15.9	$224	$0.08	$3.2
	Large	713	$158.7	$272	$0.22	$11.7
All Plants		**1,080**	**$234.9**	**$315**	**$0.21**	**$22.4**
Option C						
Government (excl. federal)	Small	47	$4.9	$1,299	$0.11	$2.3
	Large	121	$25.7	$424	$0.21	$12.7
Private	Small	185	$23.1	$325	$0.12	$3.3
	Large	713	$366.7	$629	$0.51	$16.7
All Plants		**1,080**	**$461.4**	**$619**	**$0.42**	**$22.4**

Table B-17: Compliance Costs for Electric Generators by Ownership Type and Size for Scenario Without CPP ($2013)

Ownership Type	Entity Size	Number of Plants (weighted)[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)[d]
Option D						
Government (excl. federal)	Small	47	$9.8	$2,608	$0.23	$3.3
	Large	121	$50.3	$829	$0.41	$12.7
Private	Small	185	$40.6	$573	$0.22	$5.1
	Large	713	$484.5	$832	$0.67	$16.7
All Plants		**1,080**	**$626.1**	**$839**	**$0.57**	**$22.4**
Option E						
Government (excl. federal)	Small	47	$10.8	$2,875	$0.25	$3.5
	Large	121	$55.1	$909	$0.45	$12.7
Private	Small	185	$45.6	$643	$0.24	$5.8
	Large	713	$542.9	$932	$0.75	$16.7
All Plants		**1,080**	**$695.8**	**$933**	**$0.64**	**$22.4**

a. Plant counts and cost values are sample weighted estimates.

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 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.

d. Values reflect maximum of un-weighted costs to surveyed plants only.
Source: U.S. EPA Analysis, 2015.

B.5.3 UMRA Analysis of Impact on the Private Sector

For the scenario without CPP, EPA estimates total annualized pre-tax compliance costs for private entities to range from $98 million under Option A to $589 million under Option E (*Table B-18*). Under Option D, EPA estimates that private entities will incur $525 million in total annualized pre-tax compliance costs, with maximum costs to private entities of $1,671 million in 2023.

Table B-18: Compliance Costs for Electric Generators by Ownership Type for Scenario Without CPP ($2013)

Ownership Type	Total Annualized Costs	Maximum One-Year Costs	Year of Maximum Costs
Option A			
Government (excl. federal) and Cooperatives	$9.9	$61.4	2019
Private	$97.5	$410.5	2021
Option B			
Government (excl. federal) and Cooperatives	$19.4	$98.6	2019
Private	$174.6	$668.1	2021

Table B-18: Compliance Costs for Electric Generators by Ownership Type for Scenario Without CPP ($2013)

Ownership Type	Total Annualized Costs	Maximum One-Year Costs	Year of Maximum Costs
Option C			
Government (excl. federal) and Cooperatives	$30.6	$182.9	2019
Private	$389.8	$1,313.3	2021
Option D			
Government (excl. federal) and Cooperatives	$60.1	$244.0	2019
Private	$525.1	$1,670.5	2023
Option E			
Government (excl. federal) and Cooperatives	$66.0	$256.7	2019
Private	$588.5	$1,846.1	2023

Source: U.S. EPA Analysis, 2015.

C Sensitivity Analyses

As discussed in this document, EPA conducted sensitivity analyses of the technology bases selected for the final BAT and PSES (Option D for existing sources). These sensitivity analyses assess the effects of alternative assumptions regarding the effects of the CCR final rule and under an alternative applicability scenario wherein the same ELGs would apply to all units (instead of including different requirements for existing generating units less than or equal to 50 MW and for oil-fired generating units). In particular, the Agency assessed the following sensitivity scenarios:

- *Sensitivity Scenario 1: Effects of EPA's Coal Combustion Residuals (CCR) Final Rule ("No CCR Conversions")*: The analyses and the conclusions on economic achievability presented in this report reflect consideration of wastestreams generated by steam electric power plants at the time of ELG promulgation, *i.e.*, by 2015, accounting for the effects of the final CCR rule. Specifically, EPA developed its main cost and economic impact analyses assuming that, by the time plants must meet the final rule limitations, certain plants will have made changes to their operations to comply with Resource Conservation and Recovery Act (RCRA) requirements for coal combustion residuals promulgated in April 2015. These requirements may result in certain existing steam electric power plants converting from wet to dry CCR handling, meaning that the associated wastestreams would no longer be generated and would, therefore, meet the requirements in the final ELGs. There is uncertainty in determining plant-specific response to the final CCR rule and the timing of operational changes at individual plants. Therefore, to confirm that final ELG requirements would be economically achievable in an alternative case under which the steam electric power plants may continue to generate the wastewater streams (instead of converting to dry systems), EPA conducted a sensitivity analysis around this possibility. EPA developed plant-level costs of meeting the ELG requirements assuming no change in plant wastestreams as a result of the CCR Final Rule. In particular, ignoring the effects of the CCR rule means that 8 additional plants would incur costs for meeting the final rule requirements based on under Option D; consequently, analyses in this appendix demonstrate the sensitivity of EPA's analyses to these additional costs. All other inputs and assumptions remain unchanged (*e.g.*, subcategorization of oil-fired generating units and small generating with capacity less than or equal to 50 MW).
- *Sensitivity Scenario 2: All Steam Electric Units ("All Units")*: EPA's final rule analysis assesses the costs and economic impacts of final ELGs that establish a subcategory for oil-fired generating units and small units with generating capacity of 50 MW or less. This subcategorization effectively results in these units incurring no incremental costs to meet the final ELGs. This second sensitivity scenario presents the Agency's assessment of the effects of this subcategorization on the costs and economic impacts of the final ELGs. Specifically, the Agency identified 14 of 1,080 steam electric power plants that would incur costs under Option D, absent the subcategorization. The Agency conducted this sensitivity analysis for the 1,080 steam electric power plants analyzed for the final BAT and PSES limitations and standards (Option D), assuming all other inputs and assumptions remain unchanged (*e.g.*, changes resulting from the CCR Final Rule).

Tables in this Appendix present results of these sensitivity analyses; for comparison, the tables also present results for the analysis of final Option D for the scenario without CPP from *Appendix B*.

Table C-1: Annualized Compliance Costs for Option D by Sensitivity Scenario (in millions, $2013, at 2015)[a]

	Pre-Tax Compliance Costs				After-Tax Compliance Costs			
Sensitivity Scenario	**Capital Technology**	**Other Initial One-Time**	**Total O&M**	**Total**	**Capital Technology**	**Other Initial One-Time**	**Total O&M**	**Total**
Without CPP (With CCR and 50 MW)	**$388.5**	**$0.0**	**$270.2**	**$658.7**	**$266.9**	**$0.0**	**$188.4**	**$455.3**
No CCR	$486.2	$0.0	$507.7	$993.9	$337.3	$0.0	$348.3	$685.6
All Units	$399.8	$0.0	$282.3	$682.1	$276.6	$0.0	$199.2	$475.8

a. See *Chapter 3* for a detailed discussion of the methodology used to conduct this analysis. All cost estimates are for 1,080 plants.
Source: U.S. EPA Analysis, 2015

Table C-2: Plant-Level Cost-to-Revenue Analysis Results for Option D by Sensitivity Scenario[a]

		Number of Plants with a Cost-to-Revenue Ratio of			
Sensitivity Scenario	**Total Number of Plants**	**0%[b]**	**≠0 and <1%**	**≥1 and <3%**	**≥3%**
Without CPP (With CCR and 50 MW)	1,080	899	110	54	17
No CCR	1,080	891	86	77	26
All Units	1,080	885	118	54	23

a. See *Chapter 4* for a detailed discussion of the methodology used to conduct this analysis.

b. These plants already meet discharge requirements for the wastestreams addressed by a given regulatory option and are therefore not expected to incur any compliance technology costs.
Source: U.S. EPA Analysis, 2015

Table C-3: Number of Entities Incurring Costs for Option D by Entity Size and Sensitivity Scenario[a]

	Estimate of number of entities owning steam electric power plants and incurring costs		
Sensitivity Scenario	**Total**	**Small**	**Large**
Without CPP (With CCR and 50 MW)	80	23	57
No CCR	83	24	59
All Units	87	27	60

Source: U.S. EPA Analysis, 2015

Table C-4: Entity-Level Cost-to-Revenue Analysis Results for Option D by Sensitivity Scenario[a]

Sensitivity Scenario	Case 1: Lower bound estimate of number of entities owning steam electric power plants						Case 2: Upper bound estimate of number of entities owning steam electric power plants					
	Total Number of Entities	Number of Parent Entities with a Ratio of					Total Number of Entities	Number of Parent Entities with a Ratio of				
		0%[b]	≠0 and <1%	≥1 and <3%	≥3%	Unknown		0%[b]	≠0 and <1%	≥1 and <3%	≥3%	Unknown
Without CPP (With CCR and 50 MW)	243	149	63	12	5	14	507	397	63	12	5	30
No CCR	243	146	60	15	8	14	507	394	60	15	8	30
All Units	243	142	65	14	8	14	507	388	67	14	8	30

a. Case 1 assumes that plants represented by sample weights are owned by the same firm that owns the sample plant; this is a lower-bound estimate of number of firms owning steam electric power plants. Case 2 assumes that plants represented by sample weights are owned by different firms than those owning the sample plant; this is an upper-bound estimate of number of firms owning plants that face requirements under the regulatory analysis. See *Chapter 4* for a detailed discussion of the methodology used to conduct this analysis.

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

Source: U.S. EPA Analysis, 2015

Table C-5: Projected 2015 Price (Cents per KWh of Sales) and Potential Price Increase Due to Compliance Costs for Option D by Sensitivity Scenario ($2013)[a]

Sensitivity Scenario	Compliance Cost (¢/KWh)	Residential		Commercial		Industrial		Transportation		All Sector Average	
		Baseline Price	% Change	Baseline Price	% Change	Baseline Price	% Change	Baseline Price	% Change	Baseline Price	% Change
Without CPP (With CCR and 50 MW)	0.018	11.65	0.15%	9.77	0.18%	6.30	0.28%	10.51	0.17%	9.48	0.19%
No CCR	0.026	$11.65	0.23%	9.77	0.27%	6.30	0.42%	10.51	0.25%	9.48	0.28%
All Units	0.018	11.65	0.16%	9.77	0.19%	6.30	0.29%	10.51	0.17%	9.48	0.19%

a. See *Chapter 4* for a detailed discussion of the methodology used to conduct this analysis. Cost estimates are for 1,080 plants.
Source: U.S. EPA Analysis, 2015; U.S. DOE, 2014a; U.S. DOE, 2012dc

Table C-6: Average Annual Cost per Household in 2014 for Option D by Sensitivity Scenario ($2013)[a]

Sensitivity Scenario	Total Annual Compliance Cost (at 2015; Million; $2013)	Total Electricity Sales (at 2015; MWh)	Compliance Cost per Unit of Sales ($2013/MWh)	Residential Electricity Sales (at 2015; MWh)	Number of Households (at 2015)	Residential Sales per Residential Consumer (MWh)	Annual Compliance Cost per Household ($2013)
Without CPP (With CCR and 50 MW)	$658,688,836	3,752,709,980	$0.18	1,333,214,923	124,563,540	10.70	$1.88
No CCR	$993,916,563	3,752,709,980	$0.26	1,333,214,923	124,563,540	10.70	$2.83
All Units	$682,079,078	3,752,709,980	$0.18	1,333,214,923	124,563,540	10.70	$1.95

a. See *Chapter 4* for a detailed discussion of the methodology used to conduct this analysis. Cost estimates are for 1,080 plants.
U.S. EPA Analysis, 2015; U.S. DOE, 2014a; U.S. DOE, 2012d

Table C-7: Summary of Impact of Regulatory Option D on National and Regional Markets at the Year 2030 by Sensitivity Scenario[a]

Economic Measures (all dollar values in $2013)	Baseline Value	Option D (Final Option)			Option D, No CCR in ELG Costs		
		Value	Difference	% Change	Value	Difference	% Change
National Totals							
Total Capacity (GW)	1,021	1,021	0	0.0%	1,022	1	0.1%
Existing			-1	-0.1%		0	0.0%
New Additions			1	0.1%		1	0.1%
Early Retirements			1	0.1%		0	0.0%
Electricity Prices ($/MWh)	NA	NA	NA	NA	NA	NA	NA
Generation (TWh)	4,050	4,049	-1	0.0%	4,049	-1	0.0%
Costs ($Millions)	$198,219	$198,970	$752	0.4%	$199,278	$1,059	0.5%
Fuel Cost	$104,850	$104,846	-$3	0.0%	$104,850	$0	0.0%
Variable O&M	$13,466	$13,669	$204	1.5%	$13,870	$404	3.0%
Fixed O&M	$57,563	$58,013	$450	0.8%	$58,094	$532	0.9%
Capital Cost	$22,340	$22,441	$101	0.5%	$22,464	$124	0.6%
Variable Production Cost ($/MWh)	$29.21	$29.27	$0.06	0.2%	$29.32	$0.11	0.4%
CO_2 Emissions (Million Metric Tons)	1,679	1,677	-2	-0.1%	1,676	-3	-0.2%
Hg Emissions (Tons)	7	7	0	0.0%	7	0	-0.1%
NOx Emissions (Million Tons)	1	1	0	-0.8%	1	0	-2.2%
SO_2 Emissions (Million Tons)	1	1	0	-0.1%	1	0	0.0%
HCL Emissions (Million Tons)	0	0	0	-0.5%	0	0	-0.5%

a. Numbers may not add up due to rounding. See *Chapter 5* for a detailed discussion of the methodology used to conduct this analysis.
Source: U.S. EPA Analysis, 2015

Table C-8: Summary of Market Impact Analysis Option D on Steam Electric Power Plants, as a Group, at the Year 2030 by Sensitivity Scenario[a]

Economic Measures (all dollar values in $2013)	Baseline Value	Option D (Final Option)			Option D, No CCR Conversions		
		Value	Difference	% Change	Value	Difference	% Change
National Totals							
Total Capacity (MW)	359,982	359,137	-844	-0.23%	359,701	-281	-0.08%
Early Retirements – Number of Plants	80	81	1	1.25%	81	1	1.25%
Full and Partial Retirements – Capacity (MW)	93,726	94,569	843	0.90%	94,005	279	0.30%
Generation (GWh)	1,702,140	1,698,961	-3,179	-0.19%	1,698,341	-3,799	-0.22%
Costs ($Millions)	$82,359	$82,855	$496	0.60%	$83,088	$729	0.89%
Fuel Cost	$45,313	$45,195	-$118	-0.26%	$45,170	-$143	-0.32%
Variable O&M	$7,928	$8,120	$191	2.41%	$8,307	$378	4.77%
Fixed O&M	$25,385	$25,819	$434	1.71%	$25,892	$506	1.99%
Capital Cost	$3,732	$3,721	-$11	-0.30%	$3,719	-$12	-0.33%
Variable Production Cost ($/MWh)	$31.28	$31.38	$0.10	0.33%	$31.49	$0.21	0.67%

a. Numbers may not add up due to rounding. See *Chapter 5* for a detailed discussion of the methodology used to conduct this analysis.
Source: U.S. EPA Analysis, 2015

Table C-9: Summary of Market Impact Analysis Option D Impacts on Individual Steam Electric Power Plants at the Year 2030 (Number of Steam Electric Power Plants with Indicated Effect), by Sensitivity Scenario[a]

Economic Measures	Reduction			No Change	Increase			N/A[c,d]
	≥ 3%	≥1% and <3%	<1%		<1%	≥1% and <3%	≥ 3%	
Option D (Final Rule)								
Change in Capacity Utilization[b]	10	7	54	226	79	13	12	247
Change in Generation	14	7	24	290	30	10	26	247
Change in Variable Production Costs/MWh	1	0	58	15	244	36	7	287
Option D (No CCR Conversions)								
Change in Capacity Utilization[b]	9	9	125	65	145	10	15	246
Change in Generation	17	7	134	61	146	10	27	246
Change in Variable Production Costs/MWh	1	0	68	0	234	42	17	286

a. See *Chapter 5* for a detailed discussion of the methodology used to conduct this analysis.

b. The change in capacity utilization is the difference between the capacity utilization percentages in the baseline case and post-compliance cases. For all other measures, the change is expressed as the percentage change between the baseline and post-compliance values.

c. Plants with operating status changes in either baseline or post-compliance scenario have been excluded from general table calculations.

d. The change in variable production cost per MWh could not be developed for 40 plants with zero generation in either the baseline case, Options D or Option D without CCR post-compliance cases.
Source: U.S. EPA Analysis, 2015

Table C-10: Summary of Short-Term Effect of Compliance with Regulatory Option D on National Electricity Market – 2020 by Sensitivity Scenario[a]

Economic Measures (all dollar values in $2013)	Baseline Value	Option D (Final Option)			Option D, No CCR Conversions		
		Value	Difference	% Change	Value	Difference	% Change
National Totals							
Electricity Prices ($/MWh)	NA	NA	NA	NA	NA	NA	NA
Generation (TWh)	4,100	4,099	-1	-0.0%	4,099	-1	0.0%
Costs ($Millions)	$182,039	$182,918	$879	0.5%	$183,160	$1,121	0.6%
Fuel Cost	$98,308	$98,560	$253	0.3%	$98,568	$260	0.3%
Variable O&M	$13,800	$13,960	$160	1.2%	$14,104	$304	2.2%
Fixed O&M	$52,905	$53,237	$332	0.6%	$53,320	$415	0.8%
Capital Cost	$17,027	$17,161	$134	0.8%	$17,168	$142	0.8%
Variable Production Cost ($/MWh)	$27.35	$27.45	$0.10	0.4%	$27.49	$0.14	0.5%
CO_2 Emissions (Million Metric Tonnes)	1,755	1,750	-5	-0.3%	1,749	-6	-0.3%
Mercury Emissions (Tons)	7	7	0	-0.5%	7	0	-0.5%
NOx Emissions (Million Tons)	1	1	0	-1.2%	1	0	-2.6%
SO_2 Emissions (Million Tons)	1	1	0	-0.5%	1	0	-0.6%
HCL Emissions (Million Tons)	0	0	0	-0.1%	0	0	-0.1%

a. Numbers may not add up due to rounding. See *Chapter 5* for a detailed discussion of the methodology used to conduct this analysis.
Source: U.S. EPA Analysis, 2015

Table C-11: Estimated Cost-To-Revenue Impact on Small Parent Entities for Option D by Sensitivity Scenario[a,b]

	Case 1: Lower bound estimate of number of entities owning steam electric power plants				Case 2: Upper bound estimate of number of entities owning steam electric power plants			
	Cost ≥ 1% of Revenue		Cost ≥ 3% of Revenue		Cost ≥ 1% of Revenue		Cost ≥3% of Revenue	
Sensitivity Scenario	Number of Small Entities	% of Small Entities[c]	Number of Small Entities	% of Small Entities[c]	Number of Small Entities	% of Small Entities[d]	Number of Small Entities	% of Small Entities[d]
Without CPP (With CCR and 50 MW)	10	9.1%	3	2.7%	10	5.2%	3	1.6%
No CCR	14	12.7%	5	4.5%	14	7.3%	5	2.6%
All Units	12	10.9%	6	5.5%	12	6.3%	6	3.1%

a. Case 1 assumes that plants represented by sample weights are owned by the same firm that owns the sample plant; this is a lower-bound estimate of number of firms owning steam electric power plants. Case 2 assumes that plants represented by sample weights are owned by different firms than those owning the sample plant; this is an upper-bound estimate of number of firms owning plants that face requirements under the regulatory analysis. See *Chapter 8* for a detailed discussion of the methodology used to conduct this analysis.

b. The number of entities with cost-to-revenue impact of at least 3 percent is a subset of the number of entities with such ratios exceeding 1 percent.

c. Percentage values were calculated relative to the total of 110 (Case 1) and 191 (Case 2) total small entities owning steam electric power plants.
Source: U.S. EPA Analysis, 2015

Table C-12: Summary of Annualized Costs of Compliance to Society for Option D by Sensitivity Scenario (Millions; $2013)[a]

Sensitivity Scenario	At 3 Percent	At 7 Percent
Without CPP (With CCR and 50 MW)	$640.5	$626.1
No CCR	$1,005.0	$948.5
All Units	$664.0	$648.5

a. See *Chapter 11* of the Benefits and Costs Analysis for the Final Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (BCA) report for a detailed discussion of the methodology used to conduct this analysis. Cost estimates are for 1,080 plants.
Source: U.S. EPA Analysis, 2015

D Summary of Changes to Costs and Economic Impact Analysis

Table D-1 summarizes the principal changes EPA made to analyses of the costs and economic impacts of the final rule, as compared to those used for the proposed rule (in addition to changes to inputs such as costs and pollutant loads which are discussed in the *TDD*). EPA made these changes to address comments it received on the proposed rule analysis and to incorporate updated, more recent data.

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

Report Section or Cost/Impact Category	Analysis Component [Proposed rule analysis value]	Changes to Analysis for Final Rule [Final rule analysis value]
General assumptions	Dollar year [all costs expressed in 2010 dollars]	Updated dollar year [2013]
	Promulgation year [all costs and revenue streams discounted back to 2014]	Updated promulgation year [2015]
	Period of analysis [2017-2040]	Updated period of analysis [2019-2042]
	Adjustment year [2021] for CCI-, ECI-, and GDP Deflator-based adjustment indexes. [2035] for AEO-based adjustment index	[2022] for CCI-, ECI-, and GDP Deflator-based adjustment indexes. [2040] for AEO-based adjustment index
	Technology implementation years [2017-2021]	Updated technology implementation years [2019-2023]
General inputs	Generation, plant revenue, and estimated electricity prices using EIA-861 and EIA-923 databases; three-year (2007-2009) average values used	Updated with data from more current EIA-861 and EIA-923 databases to use six-year (2007-2012) average values
	Generating capacity from 2009 EIA-860	Updated using 2012 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 [2009]	Updated to use data from EIA-861 for [2012]
	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 [2010] AEO projections	Updated using [2013] AEO projections
Industry profile	Total count of plants (1,079 plants)	Reflects updated information on actual/planned/announced unit retirements through December 31, 2024. Total count of 1,080 plants
	Industry data (*i.e.*, capacity, generation, number of facilities, etc) from 2009 EIA databases	Updated using 2012 EIA databases
	Data reported for utilities vs. non-utilities (Net summer capacity and net generation) from Electric Power Annual released in [November, 2011, updated in December 2011]	Updated using Electric Power Annual released in [November, 2013]
Screening-level plant impacts	Cost-to-revenue impact indicators (1% and 3%)	Updated to use revenue values based on 6-year (2007-2012) average values, instead of 3-year (2007-2009) values, of electricity generation and electricity prices

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

Report Section or Cost/Impact Category	Analysis Component [Proposed rule analysis value]	Changes to Analysis for Final Rule [Final rule analysis value]
Market-level impacts (IPM)	IPM platform [v 4.10]	Demand projections and other model assumptions based on 2013 Annual Energy Outlook [v 5.13]
	IPM base case	Incorporates the effects of additional regulations affecting the power generation industry, including final CCR rule, final 316(b) rule, and the proposed Clean Power rule
	NEEDS V4.10 database	New NEEDS V5.13 database
	IPM analysis run years [2020 (2017-2024), 2030 (2025-2034)]	Choose based on technology-installation window. IPMV5.13 run years: 2016 (2016-2017), 2018 (2018), 2020 (2019-2022), 2025 (2023-2027), 2030 (2028-2033), 2040 (2034-2045), and 2050 (2046-2054)
	IPM dollar year: [2007]	Dollar year in IPMV5.13 is 2011
	Compliance costs [use approximate non-CBI estimates]	Use plant-specific CBI costs allocated to generating units based on IPM unit-level capacity. Updated IPM units-to-SE units mapping.
Potential electricity price effects	Impacts on households	Enhance analysis to evaluate differential impacts on households by income level (*i.e.*, distributional analysis)
RFA/SBREFA	Small business size thresholds; [2012] SBA size thresholds	Revised analysis to use employee count-based SBA thresholds for NAICS 2211 based on Federal Register /Vol. 78, No. 246 /Monday, December 23, 2013 /Rules and Regulations. Updated analysis to reflect SBA size standards effective July 14, 2014
	Small business size determination [mostly industry survey for private entities; Census 2010 for governments]	Updated to use Census 2013 for governments (municipalities and other political subdivisions)

E Overview of IPM and Its Use for the Market Model Analysis of the Final ELGs

As discussed in *Chapter 5: Electricity Market Model Analysis*, to assess the impacts of the Steam Electric Power Generating Point Source Category (final ELGs) options, 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. Specifically, to assess plant- and market-level effects of the final ELG options, EPA used an updated version of this model: Integrated Planning Model Version 5.13 (IPM V5.13) (U.S. EPA, 2013a). This analysis is meant to inform EPA's assessment of the economic achievability of the final ELGs under CWA Section 304(b)(2). This *Appendix* provides an overview of IPM V5.13, which is the basis of the Market Model Analysis for the final ELG regulatory options.

E.1 Overview of the Integrated Planning Model

IPM V5.13 is an engineering-economic optimization model of the electric power industry, which 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 questions at the plant, regional, and national levels. In the past, 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 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, over the entire evaluated time horizon; the result is expressed as the net present value of all cost components. The objective function is minimized subject to a series of user-defined supply and demand, or system operating, constraints. Supply-side constraints include capacity constraints, availability of generation resources, plant minimum operating constraints, transmission constraints, and environmental constraints. Demand-side constraints include reserve margin constraints and minimum system-wide load requirements. The optimal solution to the objective function is the least-cost mix of resources required to satisfy system-wide electricity demand on a seasonal basis by region. In addition to existing capacity, the model also considers new resource investment options, including capacity expansion at existing plants, as well as investment in new plants. The model selects new investments while considering interactions with fuel markets, capacity markets, power plant cost and performance characteristics, forecasts of electricity demand, system reliability considerations, and other constraints. The resulting system dispatch is optimized given the resource mix, unit operating characteristics, and fuel and other costs, to achieve the most efficient use of existing and new resources available to meet demand. The model is dynamic in that it is capable of using forecasts of future conditions to make decisions for the present.

E.2 Key Specifications of the IPM V5.13

Power Plant Universe

IPM V5.13 is based on an inventory of all U.S. utility- and non-utility-owned boilers and generation plants that provide power to the integrated electric transmission grid, as recorded in the Department of Energy's Energy Information Administration (EIA) databases EIA 860 (U.S. DOE, 2006) and EIA 767 (U.S. DOE, 2005).[126] The IPM V5.13 universe consists of 16,282 generating units accounting for 5,539 existing electric power plants. The modeling system includes nearly all steam electric generating plants to which the final ELGs apply and which are estimated to incur compliance costs for the two options EPA analyzed using IPM. Plants excluded from the IPM analysis of the final ELG rule include two plants located in Alaska and six plants located in Hawaii (and thus not included in IPM), and one plant excluded from the IPM baseline as the result of custom adjustments made by ICF based on the proprietary information about existing power-plant universe, and one plant that has repowered since the IPM5.13 was developed.[127]

Potential (New) Units

In addition to *existing* electric power plants, IPM also models *potential* power plants to represent new generation capacity that may be built during a model run. All the model plants representing new capacity are pre-defined at IPM set-up and are differentiated by type of technology, regional location, and years available. IPM "builds" new capacity to ensure that electricity demand is met at the lowest possible cost. To determine whether building new capacity is more economically advantageous than letting existing plants produce enough electricity to meet market demand, IPM takes into account cost differentials between various technologies, expected technology cost improvements (by differentiating costs based on a plant's vintage, *i.e.*, build year) and regional variations in capital costs that are expected to occur over time.[128]

Electricity Demand Baseline

IPM Version 5.13 embeds a baseline energy demand forecast that is derived from the Department of Energy's *Annual Energy Outlook 2013* (AEO2013), with adjustments by EPA to account for the effect of certain voluntary energy efficiency programs. This electricity demand baseline is the same as that used by EPA in IPM-based analyses for air program regulations.

Regional Analysis Framework

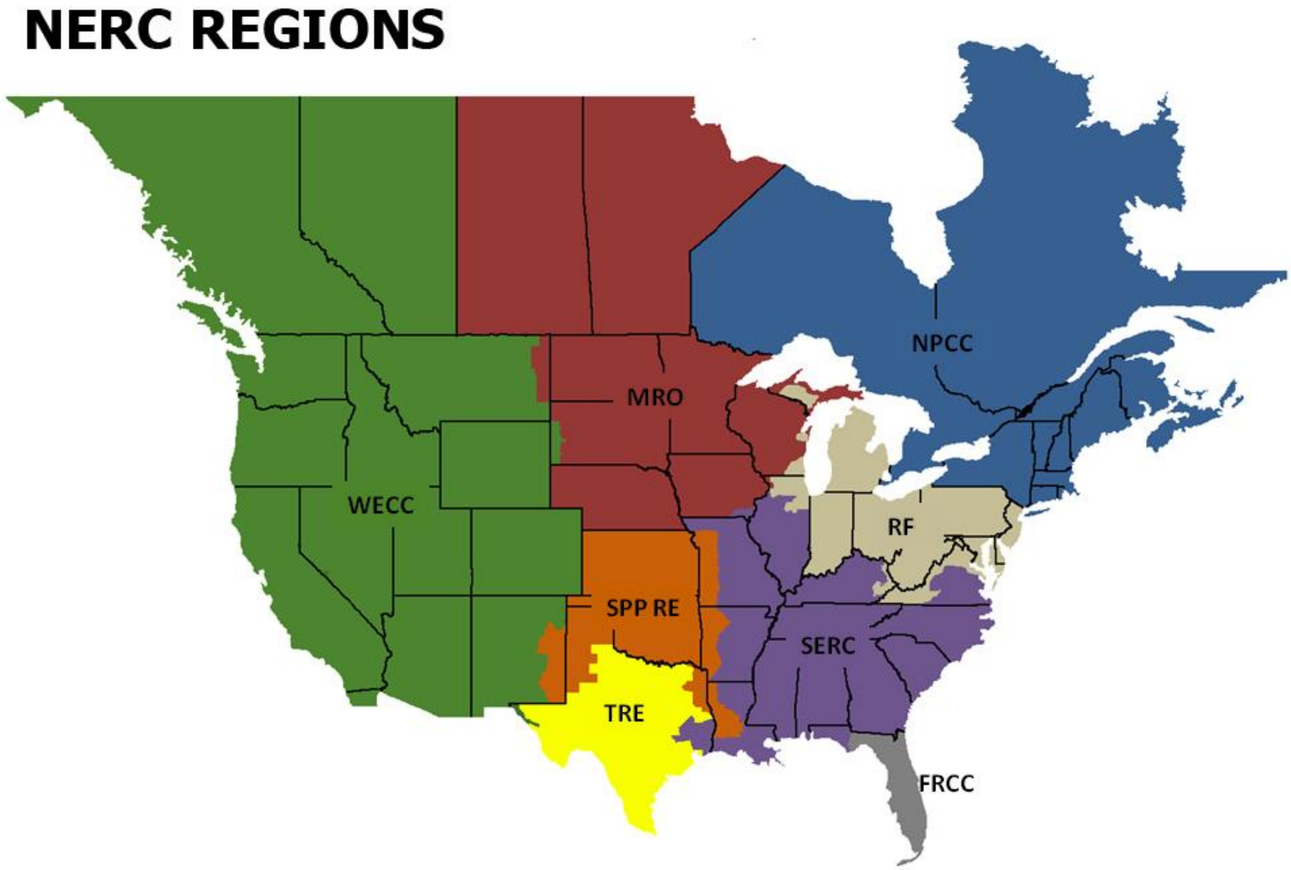
IPM V5.13 divides the U.S. electric power market into 32 regions in the contiguous 48 states. It does not include generators located in Alaska or Hawaii. The 32 regions map to North American Reliability Corporation (NERC) regions and sub-regions. IPM models electricity demand, generation, transmission, and distribution within each region and across the transmission grid that connects regions. For the analyses presented in this chapter, IPM regions were aggregated back into NERC regions. *Figure E-1*provides a map of the NERC regions and *Table E-1* lists the regions included in IPM V5.13 and a crosswalk between these NERC regions and the IPM regions.

[126] IPM generating unit universe does not include generating units in Hawaii or Alaska.

[127] EPA's analysis of electricity market impacts is based on the total of "lower-48"/grid-connected plants that responded to the Questionnaire for the Steam Electric Power Generating Effluent Guidelines (industry survey; U.S. EPA, 2010a). In the analyses described elsewhere in this report, the non-respondents are accounted in the plant sample weights (see *Technical Development Document (TDD)*). However, use of sample weights would not be appropriate in the IPM framework, and thus these "sample weight-represented" plants cannot be explicitly analyzed in the IPM-based electricity market analyses. Note, however, that these plants do not incur costs to meet the ELG requirements and therefore omission of the plants from the IPM inputs is not expected to affect the model results.

[128] For more information see IPM documentation available at http://www.epa.gov/airmarkets/progsregs/epa-ipm/index.html.

Figure E-1: 2012 North American Electric Reliability Corporation (NERC) Regions



a. The ASCC and HICC are not shown.
Source: NERC, 2015

Table E-1: Crosswalk between NERC Regions and IPM Regions[a]

NERC Region		Corresponding IPM Region(s)
ASCC	Alaska Systems Coordinating Council	Alaska plants are not included in IPM
TRE	Texas Regional Entity	ERC_FRNT, ERC_GWAY, ERC_REST, ERC_WEST
FRCC	Florida Reliability Coordinating Council	FRCC
HICC	Hawaii	Hawaii plants are not included in IPM
MRO	Midwest Reliability Organization	MAP_WAUE, MIS_IA, MIS_MAPP, MIS_MIDA, MIS_MNWI MIS_WUMS, SPP_NEBR
NPCC	Northeast Power Coordination Council	NENG_CT, NENG_ME, NENGREST, NY_Z_A&B, NY_Z_C&E, NY_Z_D, NY_Z_F, NY_Z_G-I, NY_Z_J, NY_Z_K
RFC	ReliabilityFirst Council	MIS_INKY, MIS_LMI, PJM_AP, PJM_ATSI, PJM_COMD, PJM_EMAC, PJM_PENE, PJM_SMAC, PJM_West, PJM_WMAC
SERC	Southeastern Electricity Reliability Council	MIS_IL, MIS_MO, PJM_Dom, S_C_KY, S_C_TVA, S_D_AMSO, S_D_N_AR, S_D_REST, S_D_WOTA, S_SOU, S_VACA
SPP	Southwest Power Pool	SPP_KIAM, SPP_N, SPP_SE, SPP_SPS, SPP_WEST

Table E-1: Crosswalk between NERC Regions and IPM Regions[a]

NERC Region	Corresponding IPM Region(s)
WECC Western Electricity Coordinating Council	WEC_CALN, WEC_LADW, WEC_SDGE, WECC_AZ, WECC_CO, WECC_ID, WECC_IID, WECC_MT, WECC_NM, WECC_NNV, WECC_PNW, WECC_SCE, WECC_SF, WECC_SNV, WECC_UT, WECC_WY

a. The definition and configurations of NERC regions have changed over the past few years. This report uses different NERC region configurations in different analyses, depending on the NERC region definition in which the data underlying a given analysis were reported. The NERC region framework used in the IPM Version 4.10 and underlying the Market Model Analysis is based on the current NERC region definitions.
Source: U.S. EPA, 2013a

Regulations Accounted for in the IPM Analysis Baseline

An important reason for using IPM for analyses of the final ELGs is that EPA uses the model to support analysis of air regulations and the model thus incorporates in its analytic baseline the expected compliance response for air regulations affecting the power sector. For the purpose of analyzing the final ELGs, EPA used the most current IPM baseline available at the time of analysis to make sure that this baseline reflects as much as possible the current regulatory state of the electric power industry and anticipated response to existing environmental regulations. Thus, IPM V5.13 incorporates in its analytic baseline the expected compliance response for the following air regulations affecting the power sector: the final Mercury and Air Toxics Standards (MATS) rule; the final Cross-State Air Pollution Rule (CSAPR); regulatory SO_2 emission rates arising from State Implementation Plans; Title IV of the Clean Air Act Amendments; NOx SIP Call trading program; Clean Air Act Reasonable Available Control Technology requirements and Title IV unit specific rate limits for NOx; the Regional Greenhouse Gas Initiative; Renewable Portfolio Standards; New Source Review Settlements; and several state-level regulations affecting emissions of SO_2, NOx, and Hg that were either in effect or expected to come into force by 2017.[129,130]

Treatment of Individual Plants and Generating Units

As discussed earlier, IPM is supported by a database of existing boilers and electric generation units. To reduce the size of the model and makes the model manageable while capturing the essential characteristics of the generating units, during analysis runs, individual boilers and electric generating units are aggregated into "model plants". The "model plant" aggregation scheme is used to combine existing units with similar characteristics into "model plants". It encompasses a variety of different classification categories including location, size, technology, heat rate, fuel choices, unit configuration, SO_2 emission rates, and environmental regulations among others.[131]

In the analyses for EPA air regulations, IPM aggregates individual boilers and generators with similar cost and operational characteristics into model plants. The Agency judges that this model plant aggregation is appropriate for the analysis of the final ELG options.

129 For more information on IPM V5.13 see http://www.epa.gov/airmarkets/progsregs/epa-ipm/index.html.

130 On August 21, 2012, the D.C. Circuit vacated the Cross-State Air Pollution Rule (CSAPR). The Court remanded the rule back to the Environmental Protection Agency (EPA) for further consideration. In the interim, the previously vacated Clean Air Interstate Rule (CAIR) remains in effect, for now, by a standing Court order. EPA expects that this change had a minimal effect on the results of analysis conducted in support of the final ELG.

131 For more information on IPM V5.13 see http://www.epa.gov/airmarkets/progsregs/epa-ipm/index.html.

Model Run Years

IPM V5.13 models the electric power market over the 43-year period from 2012 to 2054. Due to the highly data- and calculation-intensive computational procedures required for the IPM dynamic optimization algorithm, IPM is run only for a limited number of years. Run years are selected based on analytical requirements and the necessity to maintain a balanced choice of run years throughout the modeled time horizon. Further, depending on the analytical needs, in the IPM analysis, these *individual* run years are assigned to represent other *adjacent* years in addition to the run year itself. For the purpose of analyzing the final ELGs, EPA did not make any changes to the run-year specification already defined in IPM as the time of analysis. *Table C-2* presents run years used in the IPM analysis of the final ELGs and the years to which these run years map.

Table C-2: IPM V5.13 Run-Year Specification[a]

Run Year	Map Years
2020	2019-2022
2025	2023-2027
2030	2028-2033

a. IPM V5.13 also models run years 2016 (2016-2017), 2018 (2018), 2040 (2034-2045), and 2050 (2046-2054). However, EPA did not use the data for these run years to assess the impact of the final ELGs.

Selection of Compliance Responses

EPA did not apply a feature available in the IPM framework in which modeled plants select their compliance response to a regulation that is being analyzed. This capability is used regularly in analyses of air regulations and allows plants to be analyzed assuming a compliance response selected from a menu of options, based on the most advantageous economic outcome *to the plant*. For the analysis of the final ELG options, EPA determined the compliance response to regulatory options outside of IPM by evaluating baseline engineering factors for plants in relation to the requirements of a given regulatory option. For each plant, EPA determined the choice of technology, and its associated costs, and used the data as input to the IPM run.

F Cost-Effectiveness

F.1 Introduction

EPA is promulgating a regulation that strengthens the existing controls on discharges from steam electric power plants by revising technology-based effluent limitations guidelines and standards (ELGs) for the Steam Electric Power Generating point source category, 40 CFR part 423.

EPA has traditionally calculated cost-effectiveness—defined as the ratio of annual compliance costs of a regulatory option divided by the option's toxicity-weighted pounds of pollutants removed annually—as one of several metrics in developing ELGs. The Agency uses cost-effectiveness during the rulemaking process to inform its understanding of the relative efficiency of alternative regulatory options in removing toxic pollutants from effluent discharges to the nation's waters. Cost-effectiveness is not a factor that the Clean Water Act (CWA) specifies for establishing ELGs based on Best Available Technology (BAT) Economically Achievable. It is not indicative of economic achievability. Furthermore, cost-effectiveness is an incomplete metric and does not provide an effective way to identify regulatory options that are better at preventing or mitigating environmental harm posed by industrial discharges (see *Section F.4* for a discussion of limitations). Accordingly, EPA does not typically select or reject options on the basis of their cost-effectiveness alone but may use cost-effectiveness to characterize and compare regulatory options.

One purpose of a cost-effectiveness analysis is to compare options within a given rule. The incremental cost-effectiveness values can be thought of as the marginal price that society must pay to achieve an additional unit of toxicity normalized pollutant removals. Thus, the value is a per-unit cost to society for removals. Within the set of options being considered for a regulation, some options, when compared to other options, may have *relatively high* cost-effectiveness while others may have *relatively low* cost-effectiveness. The most cost-effective option on a simple numerical basis is generally considered the option with the lowest cost-effectiveness value.

A second use of cost-effectiveness analysis is to compare the values for a particular rule with those for previously promulgated rules. If all dollar values are expressed in consistent terms, such as the recommended units of 1981 dollars, such comparisons are valid, within the confines and meaning of the cost-effectiveness values.[132] The cost-effectiveness values of options being considered for a new rule can be compared to the values of previously promulgated rules to determine the cost-effectiveness of the new rule relative to the historical rules. This comparison rests on an understanding that, to the extent that the collective actions of rulemaking processes, legislative reviews, and court reviews may be judged to reveal information about society's willingness to pay for additional pollutant removals, a comparison of the cost-effectiveness values for a regulation under development with those of previously implemented regulations may yield insight into the question of whether a regulatory option is cost-effective and which of several competing options may be most cost-effective, again recognizing the confines and meaning of cost-effectiveness values (see *Section F.4* for a discussion of limitations).

[132] Although the TWFs for priority or other pollutants may be revised over time, thus potentially altering pound-equivalent removals, the convention is to use the TWFs at the time of regulation and not recalculate historical analyses.

This appendix describes EPA's analysis of the cost-effectiveness of the final ELGs. It also compares the cost-effectiveness of the final ELGs with that of other promulgated ELGs. EPA calculated the cost-effectiveness of the regulatory options for both the analysis scenario discussed in the main body of the report ("with CPP"), as well as the alternate analysis scenario presented in *Appendix B*, which excludes the effects of the CPP rule ("without CPP").

F.2 Methodology

F.2.1 Background

Cost-effectiveness is evaluated 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 guidelines and standards and incidentally removed along with regulated pollutants. EPA's cost-effectiveness assessment does not analyze removal efficiencies for conventional pollutants, such as oil and grease or biological oxygen demand. Thus, this appendix does not address the removal of conventional pollutants.

EPA's cost-effectiveness analysis involves the following steps to generate input data and calculate the desired values:

3. Determine the pollutants considered for regulation—so-called "pollutants of concern."
4. For each pollutant, obtain relative toxic weights and POTW removal factors (as discussed in Section F.2.2 below, the first factor adjusts the removals to reflect the relative toxicity of the pollutants while the second factor reflects the ability of a POTW or sewage treatment plant to remove pollutants prior to discharge to waters).
5. Define the regulatory pollution control options.
6. Calculate pollutant removals and toxic-weighted pollutant removals for each control option and for each of direct and indirect discharges.
7. Determine the total annualized compliance cost for each control option and for direct and indirect dischargers.
8. Adjust the cost obtained in step 5 to 1981 dollars.
9. Calculate the cost-effectiveness ratios for each control option and for direct and indirect dischargers.

F.2.2 Toxic Weights of Pollutants and POTW Removal

The *Technical Development Document (TDD)* provides information on the pollutants of concern addressed by the final ELGs (U.S. EPA, 2015c). The 50 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.)

EPA's cost-effectiveness analysis accounts for differences in the toxicity of pollutants of concern through the use of toxic weighting factors (TWFs). These weighting factors offer a way to compare, on a common basis, quantities of different pollutants, each with different potential effects on human and aquatic life. The TWFs that EPA has traditionally used to develop effluent guidelines and standards are based on two values: the chronic aquatic life value and the human health value (U.S. EPA, 2006). The chronic aquatic life value indicates the concentration in water, measured in μg/L, at which a pollutant has a toxic effect on aquatic life.

The human health value, also measured in μg/L, indicates the concentration in water that would cause harm to humans eating at least 6.5 grams of fish per day from that water.[133] These values are standardized by relating them to copper, a toxic metal pollutant that is commonly detected and removed from industrial effluent. EPA uses the value of 5.6 μg/L as the benchmark figure based on the concentration at which copper becomes toxic, based on the 1980 ambient water quality criteria for copper.[134] TWFs are calculated as follows:

[Eq. 1] $$TWF_i = \frac{5.6}{AQ_i} + \frac{5.6}{HH_i}$$

where TWF_i = toxic weighting factor for pollutant *i*,

AQ_i = chronic aquatic life value (μg/L) for pollutant *i*, and

HH_i = human health value (organisms only) (μg/L) for pollutant *i*.

As indicated by *Equation 1*, high human health and aquatic life figures lead to low TWFs. In other words, if a pollutant causes adverse effects only at high concentrations, then it will have a low TWF. For details of the TWFs EPA used in this analysis, see report entitled *Review of Toxic Weighting Factors in Support of the Final Steam Electric Effluent Limitations Guidelines and Standards* (DCN SE04442) in the final rule record.

By multiplying the reduction in industry loadings (pound per year) of each pollutant by each pollutant's TWF and summing this product across all pollutants of concern, EPA derives the total toxic-weighted pollutant removals (pounds equivalent per year) attributable to each regulatory option.

Calculating pound equivalent for direct dischargers differs from calculating for indirect dischargers because of the ability of POTW to remove certain pollutants. For direct dischargers, the instream pollutant reductions are equal to end-of-pipe (*i.e.*, at the edge of the plant) pollutant removals since there is no interceding treatment between the discharge and the receiving waterbody. For indirect dischargers, instream pollutant reductions represent end-of-pipe pollutant removals and any additional pollutant removals resulting from the treatment in place at the POTW. Thus, pollutant loadings discharged to surface water from an indirect discharging plant may be less than pollutant loadings leaving the plant. For example, if an indirect discharging plant discharges 100 pounds of cadmium to a POTW, and the POTW has a removal efficiency for cadmium of 90 percent, then only 10 pounds of cadmium from the indirect discharger would be discharged to surface waters (100 pounds × 100%-90%). However, if the indirect discharging plant changes its waste treatment operations to meet the ELGs and reduces its indirect discharges of cadmium from 100 pounds to 60 pounds (40 percent reduction), the cadmium discharged to surface waters decreases to 6 pounds. Thus, the net reduction in cadmium discharged to surface waters attributable to the regulation is not 40 percent of its baseline discharge to the POTW (40 pounds), but rather 40 percent of the 10 pounds of the steam electric power plant's cadmium that are ultimately discharged to surface waters at baseline, or 4 pounds.

[133] For carcinogenic substances, EPA considers a concentration that would lead to more than 1 in 100,000 additional cancer cases over background to be harmful.

[134] Although EPA revised the water quality criterion for copper in 1998 (to 9.0 μg/L), the TWF method uses the former criterion (5.6 μg/L) to facilitate comparisons with cost-effectiveness values calculated for other regulations. This is valid because all cost-effectiveness measures are relative. The former criterion for copper (5.6 μg/L) was reported in the 1980 Ambient Water Quality Criteria for Copper document (U.S. EPA, 1980).

Table F-1 lists the pollutants that are considered in the cost-effectiveness analysis and presents their TWFs and POTW removal efficiencies, if applicable.[135]

Table F-1: Toxic Weighting Factors of Pollutants of Concern for Final ELGs[a]

Pollutant Name	Toxic Weighting Factor
Aluminum	0.065
Antimony	0.012
Arsenic	3.469
Barium	0.002
Beryllium	1.057
Boron	0.008
Cadmium	22.758
Calcium	0.000
Chloride	0.000
Chromium	0.076
Chromium (VI)	0.517
Cobalt	0.114
Copper	0.623
Cyanide	1.117
Fluoride	0.035
Iron	0.006
Lead	2.240
Magnesium	0.001
Manganese	0.103
Mercury	110.033
Molybdenum	0.201
Nickel	0.109
Nitrate Nitrite as N	0.003
Potassium	0.001
Selenium	1.121
Silver	16.471
Sodium	0.000
Strontium	0.000
Sulfate	0.000
Sulfide (as S)	2.801
Thallium	2.855
Titanium	0.029
Vanadium	0.280
Zinc	0.047

[a]: The table provides only those pollutants with a toxic weighting factor and exclude additional pollutants present in steam electric power generating plant discharges such as total phosphorus, total suspended solids, etc.

Source: U.S. EPA, 2015c

[135] See the Technical Development Document for a description of POTW removal efficiencies.

F.2.3 Regulatory Options

EPA analyzed five regulatory options evaluated for the final ELGs (see *Table 1-2*). The *TDD* provides additional information on the control technologies and regulatory options (U.S. EPA, 2015c).

F.2.4 Pollutant Removals and Pound Equivalent Calculations

EPA calculated the post-compliance pollutant loadings under the baseline (*i.e.*, current conditions) and under each regulatory option. EPA then weighted the plant-level loadings of all surveyed plants to reflect total industry-wide loadings using sample weights. The *TDD* provides the details of this analysis (U.S. EPA, 2015c).

Pollutant removals are calculated simply as the difference between the baseline and post-compliance loadings under each regulatory option [136] EPA converts the loadings into pound equivalent at the point of discharge into surface water for the cost-effectiveness analysis as follows:

For direct dischargers, pound equivalent removals are calculated as:

[Eq. 2] $$Total\ direct\ removals = \sum_{i=1}^{46} Direct\ Removals\ (lbs)_i \times TWF_i$$

For indirect dischargers, pound equivalent removals are calculated as:

[Eq. 3] $$Total\ indirect\ removals = \sum_{i=1}^{46} Indirect\ Removals\ (lbs)_i \times TWF_i \times POTW\%_i$$

Table F-2 presents estimates of the annual reduction in mass loading of pollutant anticipated from direct and indirect dischargers at the point of discharge for each regulatory option, accounting for pollutant toxicity and POTW removals.

Table F-2: Pollutant Removal by Regulatory Option

Option	Toxic-Weighted Removals (lbs-eq/yr)		
	Direct Discharge	Indirect Discharge	Total[a]
With CPP			
A	890,073	1,150	891,223
B	1,009,550	1,293	1,010,843
C	1,260,601	1,293	1,261,894
D	1,353,301	1,556	1,354,857
E	1,382,870	1,561	1,384,431

136 EPA estimated load reductions associated with each regulatory option conservatively by assuming that plants with existing treatment meet the best achievable technology (BAT) concentrations in the baseline, even in cases where the existing treatment is not meeting the BAT. This approach tends to underestimate the loading reductions associated with regulatory options.

Table F-2: Pollutant Removal by Regulatory Option

Option	Toxic-Weighted Removals (lbs-eq/yr)		
	Direct Discharge	Indirect Discharge	Total[a]
Without CPP			
A	1,019,512	6,649	1,026,161
B	1,165,862	7,531	1,173,393
C	1,476,819	7,531	1,484,350
D	1,671,398	8,275	1,679,674
E	1,705,017	8,497	1,713,514

[a] Total may not add up due to independent rounding.
Source: U.S. EPA analysis, 2015

F.2.5 Annualized Compliance Costs

EPA developed costs for technology controls to address each of the wastestreams present at each steam electric power plant. The *TDD* provides additional details on the methods used to estimate the costs of meeting the limitations and standards under each of the regulatory options (U.S. EPA, 2015c). The method used to calculate the annualized compliance costs is described in greater detail in *Chapter 3: Compliance Costs*. This section provides a summary of these costs.

For a given regulatory option, a steam electric power plant may need to meet limitations for one or more wastestreams, depending on the plant configuration, technologies in use, or other site-specific factors. The cost estimates reflect the incremental costs attributed only to the final ELGs, accounting for wastestreams and treatment systems present in the baseline.[137]

As described in *Chapter 3*, EPA evaluated two principal categories of compliance costs: capital costs and operating and maintenance (O&M) costs. While the O&M costs are recurring costs, the capital costs are "lump-sum" costs incurred only once during the (relatively long) life of the technology. EPA annualized costs as needed using 7 percent. EPA used the total pre-tax annual compliance costs to calculate cost-effectiveness values. EPA categorized the annualized compliance costs as either direct or indirect based on the discharge associated with each wastestream at each plant.[138] Finally, EPA applied sample weights to the costs for surveyed plants to obtain total costs for the 1,080 steam electric power plants. *Table F-3* summarizes the total annualized compliance costs used in calculating cost-effectiveness of the five options.

[137] EPA assigned compliance costs to plants based on the difference between existing treatment in place in the baseline and the treatment associated with a given regulatory option. In cases where a plant had existing treatment that did not meet the option treatment level, EPA conservatively assumed that the plant would incur the full compliance costs for the treatment control (*i.e.*, a plant with biological treatment that does not meet the BAT treatment levels incurs the full costs of implementing biological treatment even if actual compliance costs may be significantly lower). This approach tends to overestimate compliance costs of regulatory options.

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

Table F-3: Total Annualized Compliance Costs by Regulatory Option

Option	Total Annualized Compliance Costs (Million 2013$)		
	Direct Discharge	Indirect Discharge	Total[a,b]
With CPP			
A	$121.0	$0.8	$121.8
B	$202.8	$1.3	$204.1
C	$398.7	$1.3	$400.0
D	$490.9	$5.1	$496.1
E	$548.0	$5.8	$553.8
Without CPP			
A	$139.7	$2.8	$142.5
B	$240.8	$4.7	$245.5
C	$480.6	$4.7	$485.4
D	$648.4	$10.0	$658.4
E	$719.2	$12.8	$732.0

[a] Total may not add up due to independent rounding.

[b] Costs exclude three plants with zero discharge.

Source: U.S. EPA Analysis, 2015

F.2.6 Calculation of Cost-Effectiveness and Incremental Cost-Effectiveness Values

EPA calculates cost-effectiveness ratios separately for direct and indirect dischargers.

Typically, the cost-effectiveness for a particular control option is the ratio of the annual cost of that option to the pound-equivalents removed by that option. The incremental effectiveness of progressively more stringent regulatory options can be assessed both in comparison to the baseline scenario and to another regulatory option. The analysis reports cost-effectiveness values in units of dollars per pound-equivalent of pollutant removed.

For the purpose of comparing cost-effectiveness values of options under review for the final ELGs to those of other promulgated rules, EPA adjusts compliance costs for this analysis from 2013 to 1981 dollars using *Engineering News Record's* Construction Cost Index (CCI) as follows:

[Eq. 4] $$\text{Adjustment factor} = = \frac{3535}{9547} = 0.370$$

The equation used to calculate incremental cost-effectiveness is:

[Eq. 5] $$CE_k = \frac{TAC_k - TAC_{k-1}}{PE_k - PE_{k-1}}$$

where CE_k = incremental cost-effectiveness of Option k,

TAC_k = total annualized cost of compliance under Option k, and

PE_k = pound-equivalents removed by Option k.

The numerator of the equation, TAC_k minus TAC_{k-1}, is the incremental annualized treatment cost in going from Option k-1 (an option that removes fewer pound equivalent of pollutants) to Option k (an option that removes more pound equivalent of pollutants). The denominator is the incremental removals achieved in going from Option k-1 to Option k. The incremental cost-effectiveness values show how much more it would cost per incremental pound-equivalent of pollutant removed to go from one level of stringency to the next higher level of stringency.

F.2.7 Comparisons of Cost-Effectiveness Values

EPA presents two comparisons of the cost-effectiveness values for the final steam electric industry ELGs. First, EPA compares the cost-effectiveness of each regulatory option relative to one another. Next, EPA compares the cost-effectiveness values to cost-effectiveness values for promulgated ELGs for other industries.

F.3 Cost-Effectiveness Analysis Results

EPA prepared the cost-effectiveness analyses for the five regulatory options summarized in *Table D-1* under the scenario with CPP. In each case, EPA analyzed the cost-effectiveness of the regulatory option separately for direct and indirect dischargers.

This section first presents the total costs, total removals, cost-effectiveness, and incremental cost-effectiveness values for each option and subcategory of dischargers covered by the final ELGs (*Section F.3.1*). It then compares the cost-effectiveness values to those for ELGs previously promulgated for other industrial categories (*Section F.3.2*).

F.3.1 Cost-Effectiveness of Regulatory Options

Table F-4 shows the cost-effectiveness results for five regulatory options EPA analyzed for the final ELGs for direct and indirect dischargers.

For the scenario with CPP, cost-effectiveness values for direct dischargers range from $50/lb-eq to $134/lb-eq, with options A and E being the most and least cost-effective, respectively. Relative trends are the same for the scenario without CPP, which shows cost-effectiveness values ranging from $51/lb-eq (Option A) to $156/lb-eq (Option E) for direct dischargers,

Incremental toxic-weighted pollutant removals achieved by moving from Option B to Option C come at the lowest incremental cost for direct dischargers ($253/lb-eq and $256/lb-eq for the scenarios with and without CPP, respectively).

For indirect dischargers, cost-effectiveness values range from $246/lb-eq to $1,385/lb-eq for the scenario with CPP, and from $156/lb-eq to $559/lb-eq for the scenario without CPP. Very few plants incurring costs under any of the five options analyzed have indirect discharges only (three plants under the scenario with CPP), as compared to plants that discharge directly to surface waters only (141 plants for the scenario with CPP), or have both direct and indirect discharges (1 plant), and therefore calculations of cost-effectiveness for indirect dischargers is based on very few observations. Additionally, one of the indirect dischargers currently recycles a high share of its wastewater and may not, in fact, incur the full conversion costs EPA assumed in its analysis. If instead EPA assumes that the plant can manage its existing system to achieve full recycling, the cost-effectiveness for indirect dischargers are much lower, or $775/lb-eq for Option D (as compared to $1,228/lb-eq presented in *Table F-4*).

It is important to note that cost-effectiveness is a limited metric for understanding the net value or performance efficiency of given regulatory options, as discussed in *Section F.4*.

Table F-4: Cost-Effectiveness of Regulatory Options by Discharger Category[a]

Discharger Category	Option	Total Annual Pre-tax Compliance Costs (million, 1981$)		Total Annual TWF-Weighted Pollutant Removals (lb-eq.)		Cost-Effectiveness (1981$/lb eq)	
		Option	Incremental	Option	Incremental	Option	Incremental
With CPP							
Direct	**A**	$44.8	$44.8	890,073	890,073	$50	$50
	B	$75.1	$30.3	1,009,550	119,477	$74	$253
	C	$147.6	$72.5	1,260,601	251,051	$117	$289
	D	$181.8	$34.2	1,353,301	92,701	$134	$368
	E	$202.9	$21.1	1,382,870	29,569	$147	$714
Indirect	**A**	$0.3	$0.3	1,150	1,150	$246	$246
	B	$0.5	$0.2	1,293	143	$372	$1,384
	C	$0.5	$0.0	1,293	0	$372	0
	D	$1.9	$1.4	1,556	263	$1,228	$5,441
	E	$2.2	$0.3	1,561	5	$1,385	$50,569
Without CPP							
Direct	**A**	$51.7	$51.7	1,019,512	1,019,512	$51	$51
	B	$89.2	$37.4	1,165,862	146,350	$76	$256
	C	$178.0	$88.8	1,476,819	310,957	$121	$286
	D	$240.1	$62.1	1,671,398	194,579	$144	$319
	E	$266.3	$26.2	1,705,017	33,618	$156	$780
Indirect	**A**	$1.0	$1.0	6,649	6,649	$156	$156
	B	$1.8	$0.7	7,531	881	$233	$814
	C	$1.8	$0.0	7,531	0	$233	0
	D	$3.7	$2.0	8,275	745	$448	$2,619
	E	$4.7	$1.0	8,497	222	$559	$4,712

[a] Incremental costs (and removals) are compared to those for the next least stringent option – under Option A, the incremental costs (and removals) are calculated relative to baseline (*i.e.*, 0), for Option B, the incremental costs (and removals) are calculated relative to those of Option A, etc.
Source: U.S. EPA Analysis, 2015

F.3.2 Comparison with Previously Promulgated Effluent Guidelines and Standards

Table F-5 presents, for direct dischargers across a range of industries, the estimated cost-effectiveness for promulgated ELGs. *Table F-6* provides similar information for indirect dischargers.

The values presented in the table can be compared to the cost-effectiveness calculated for the final ELGs. This type of comparison is only possible using the cost-effectiveness values based on pound-equivalent removals estimated using the TWF weighting approach. All costs are in 1981 dollars.

The cost-effectiveness of the final BAT technology bases for direct dischargers (Option D) is $134 for the scenario with CPP and $144 for the scenario without CPP (see *Table F-4*). This is comparable to cost-effectiveness ratios for BAT of other industries shown in *Table F-5*. A review of approximately 25 of the most recently promulgated or revised BAT limitations shows BAT cost-effectiveness ranging from less than $1/lb-eq (Inorganic Chemicals) to $404/lb-eq (Electrical and Electronic Components), in 1981 dollars.

The technology bases for the final PSES option that reduce loads from indirect dischargers (Option D; see *Table F-4*) have a cost-effectiveness of $1,228/lb-eq ($1981) and $559, respectively for the scenarios with and without CPP. This cost-effectiveness ratio is higher than cost-effectiveness for PSES of other industries shown in *Table F-6*. A review of approximately 25 of the most recently promulgated or revised categorical pretreatment standards shows PSES cost-effectiveness ranging from less than $1/lb-eq (Inorganic Chemicals) to $380/lb-eq (Transportation Equipment Cleaning), in 1981 dollars.

Table F-5: Industry Comparison of Cost-Effectiveness for Direct Dischargers

Industry	40 CFR Part	Year	Cost-Effectiveness ($1981/lb.eq.)[a]
Aluminum Forming	467	1983	121
Battery Manufacturing	461	1984	2
Canned and Preserved Fruits and Vegetable Processing	407	1974	10
Canned and Preserved Seafood (Seafood Processing)	408	1974	10
Centralized Waste Treatment	437	2000	7
Coal Mining	434	1985	BAT=BPT
Coil Coating	465	1983	49
Copper Forming	468	1983	27
Electrical and Electronic Components	469	1983	404
Inorganic Chemicals I	415	1982	<1
Inorganic Chemicals II	415	1982	6
Iron and Steel	420	1982	2
Leather Tanning	425	1982	BAT=BPT
Metal Finishing	433	1983	12
Metal Molding and Castings (Foundries)	464	1985	84
Metal Products and Machinery	438	2003	50
Nonferrous Metals Forming and Metal Powders	471	1985	69
Nonferrous Metals Manufacturing I	421	1984	4
Nonferrous Metals Manufacturing II	421	1984	6
Offshore Oil and Gas (Coastal Produced Water/TWC)	435	1979	35
Organic Chemicals	414	1987	5
Pesticide Chemicals Manufacturing	455	1993	14
Petroleum Refining	419	1982	BAT=BPT
Pharmaceutical Manufacturing A/C	439	1983	47
Pharmaceutical Manufacturing B/D	439	1983	96
Plastics Molding and Forming	463	1984	BAT=BPT
Porcelain Enameling	466	1982	6
Pulp, Paper and Paperboard	430	1998	39
Textile Mills	410	1982	BAT=BPT
Transportation Equipment Cleaning	442	2000	BAT=BPT
Waste Combustors	444	2000	65

[a] TWFs for some priority pollutants have changed since each rule was promulgated. The table reflects the cost-effectiveness calculated based on the applicable TWFs at the time of promulgation.
Source: U.S. EPA analysis, 2015

Table F-6: Industry Comparison Cost-Effectiveness for Indirect Dischargers

Industry	40 CFR Part	Year	Cost-Effectiveness ($1981/lb.eq.)[a]
Aluminum Forming	467	1983	155
Battery Manufacturing	461	1984	15
Canned and Preserved Fruits and Vegetable Processing	407	1974	38
Canned and Preserved Seafood (Seafood Processing)	408	1974	39
Centralized Waste Treatment	437	2000	175
Coal Mining	434	1985	NA
Coil Coating	465	1983	10
Copper Forming	468	1983	10
Electrical and Electronic Components	469	1983	14
Inorganic Chemicals I	415	1982	9
Inorganic Chemicals II	415	1982	<1
Iron and Steel	420	1982	6
Leather Tanning	425	1982	111
Metal Finishing	433	1983	10
Metal Molding and Castings (Foundries)	464	1985	116
Metal Products and Machinery	438	2003	127
Nonferrous Metals Forming and Metal Powders	471	1985	90
Nonferrous Metals Manufacturing I	421	1984	15
Nonferrous Metals Manufacturing II	421	1984	12
Offshore Oil and Gas (Coastal Produced Water/TWC)	435	1979	NA
Organic Chemicals	414	1987	34
Pesticide Chemicals Manufacturing	455	1993	18
Pesticide Chemicals Formulating and Packaging	455	1998	<3
Petroleum Refining	419	1982	NA
Pharmaceutical Manufacturing A/C	439	1983	NA
Pharmaceutical Manufacturing B/D	439	1983	NA
Plastics Molding and Forming	463	1984	NA
Porcelain Enameling	466	1982	14
Pulp, Paper and Paperboard	430	1998	65
Textile Mills	410	1982	NA
Transportation Equipment Cleaning	442	2000	380
Waste Combustors A	442	2000	85
Waste Combustors B	444	2000	88

NA = Not applicable

[a] TWFs for some priority pollutants have changed since each rule was promulgated. The table reflects the cost-effectiveness calculated based on the applicable TWFs at the time of promulgation.

Source: U.S. EPA analysis, 2015

F.4 Sensitivity of Cost-Effectiveness Values to the Removal of Non-Detects

As noted in Section 10.2.2 of the TDD (U.S. EPA, 2015c), the sample-specific detection levels for the ash transport water data used for this rule vary widely between samples and across plants. Commenters expressed concern that the use of data with relatively high detection levels in the dataset of ash samples could overestimate the averaged pollutant loadings and the associated cost-effectiveness of EPA's action on the ash wastestreams. To address this concern and provide further transparency, EPA derived estimates of pollutant loadings using two methods. Method 1, as already described in the TDD and elsewhere in the rule package, uses both the detect and non-detect data, (assigning one-half of the detection limit for all non-detects). Method 2 excludes all non-detect observations that have an attributed value (*i.e.*, one-half of the detection limit) that are higher than the highest detected value for that pollutant in the data set. Section 10.2.2 of the TDD describes the method 2 analysis. EPA conducted analysis using method 2 in order to place an upper bound on the effect of potential outlier non-detects on the pounds of pollutants removed and TWPEs removed under the final rule. This analysis showed that removing non-detect values that could potentially be considered outliers resulted in changes in the average pollutant concentrations for 6 out of 44 analytes: antimony, cobalt, molybdenum, silver, thallium, and titanium.

In this section, we further apply the results of the method 2 analysis described in Section 10.2.2 of the TDD to calculate the effect of non-detects that could be considered outliers on the cost-effectiveness of the bottom ash wastestream and for the full rule. *Table F-7* contains the method 1 results, while *Table F-8* contains the method 2 results (when non-detects that could be considered outliers are removed). Taken together, *Tables F-7* and *F-8* show that cost effectiveness when comparing the results of the two methods ranges from $314/TWPE to $457/TWPE for bottom ash and from $136/TWPE to $149/TWPE for the full rule.

Table F-7: Pollutant Loadings and Cost-Effectiveness for Method 1, Not Excluding High ND

	Total Annual Pollutant Removals[a,b] (lbs)	Total Annual TWF-Weighted Pollutant Removals (lb-eq.)[a]	Cost-Effectiveness (1981$/lb-eq)[a]
Bottom Ash Transport Water (> 50 MW)	238,810,677	344,014	$314
Full Rule (Option D)	371,152,958	1,354,857	$136

[a] Pollutant removals, costs, and cost-effectiveness based on total of direct and indirect dischargers.
[b] Excludes removals for pollutants not identified as POCs and for BOD, COD, TSS, and TDS
Source: U.S. EPA analysis, 2015

Table F-8: Pollutant Loadings and Cost-Effectiveness for Method 2, Excluding High ND

	Total Annual Pollutant Removals[a,b] (lbs)	Total Annual TWF-Weighted Pollutant Removals (lb-eq.)[a]	Cost-Effectiveness (1981$/lb-eq)[a]
Bottom Ash Transport Water (> 50 MW)	238,735,119	236,402	$457
Full Rule (Option D)	371,048,709	1,233,553	$149

[a] Pollutant removals, costs, and cost-effectiveness based on total of direct and indirect dischargers.
[b] Excludes removals for pollutants not identified as POCs and for BOD, COD, TSS, and TDS
Source: U.S. EPA analysis, 2015

EPA conducted the two analyses to bound the estimated baseline pollutant loadings and removals; the actual baseline pollutant loadings and the resulting removals and cost effectiveness of the final rule likely fall somewhere between the estimated values shown in *Tables F-7* and *F-8*. In applying the results of these two methods EPA selected the more conservative approach, method 1, to ensure we modeled plausible worst-case pollution scenarios. Our analysis of the difference between the two methods leads EPA to conclude that the total pounds of contaminants do not vary significantly and the mean values for only six analytes are affected when the less conservative method 2 is used. EPA's determination of BAT and the standards and rationale supporting that determination are discussed in the preamble (Section VIII), and the range of loadings and cost effectiveness values established using the two methods does not alter that BAT determination.

F.5 Uncertainties and Limitations

There are several important caveats regarding the evaluation of cost-effectiveness values in the context of ELG development.

- *There are no absolute scales for judging cost-effectiveness values as indicating that an option is "cost effective" or "not cost-effective."* The values are considered comparatively high or low only within a given context such as regulatory options or industries with similar discharge characteristics.
- *The cost-effectiveness of one option compared to another, or to that of other industries, provides no meaningful insight as to the reduction in risk or potential for human health or ecological impacts.* Cost-effectiveness is not a measure of observed environmental impacts, nor will the cost-effectiveness ranking necessarily correlate to the degree to which actual or modeled environmental impacts are mitigated. TWFs are not a measure of risk or potential for human health or ecological impacts. TWFs are derived from chronic aquatic life criteria (or toxic effect levels) and human health criteria or toxic effect levels *established for the consumption of fish*, where available; in cases where only one of the two criteria is available, TWFs account for only the particular type of harm. In the TWF method for assessing water-based effects, these toxicity levels of pollutants of concern are compared to a benchmark value that represents the toxicity of copper.
- *The cost-effectiveness of one option compared to another, or to that of other industries, provides no meaningful insight to the relative environmental benefits of the options.* Loading reductions used to calculate the cost-effectiveness are not a measure of environmental benefits. They do not, in any way, account for the range of effects on the waterbody in which the pollutants are discharged and surrounding population that may be exposed to the pollution. Only detailed exposure assessment data, based on an analysis of the fate and transport of pollutant discharge, exposure pathways, and uptake, would provide the information necessary to evaluate the extent to which regulatory options reduce environmental impacts and enhance human and ecological health. Site-specific conditions in the receiving waterbody, including hydrodynamics, exposed fauna and biota, etc. can result in different environmental effects beyond those that may be suggested by comparing pollutant mass only, even when adjusted for toxicity. Additionally, the cost-effectiveness analysis does not address routes of potential environmental damage and human exposure, and therefore potential benefits from reducing pollutant exposure, other than via surface waters.
- *Cost-effectiveness is based on an incomplete accounting of pollutant reductions*. Cost-effectiveness does 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).[139] Thus, regulatory options that achieve additional conventional pollutant reductions for incremental costs as compared to other options that reduce toxic pollutant loads only, would have a relatively higher cost per TWPE removed, despite potentially providing greater ecosystem and water quality improvements.

[139] As noted above, EPA may also calculate separate nutrient cost-effectiveness values (*e.g.*, expressed as $/lb nitrogen or $/lb phosphorus) for options that achieve nutrient removals. EPA may similarly calculate separate cost-reasonableness ratios based on the removal of conventional pollutants (BOD, TSS, fecal coliform, pH, and oil and grease).

- *Cost-effectiveness analysis does not address economic achievability*. An option may be economically achievable, yet still not judged to be more cost-effective than another. For example, an option determined to be economically achievable based on affordability to the industry as a whole may be judged to be less cost-effective than another option, particularly if there are relatively low levels of pollutants available for removal when moving to the given option. Conversely, the aggregate costs of the regulatory option and its associated burden on industry and the economy may cause a regulatory option to not be economic achievable, regardless of its cost-effectiveness.
- *The basis for calculating cost-effectiveness has changed over time and across regulations.* While EPA restates costs in 1981 dollars to allow comparison across ELGs, it typically has not restated toxic-weighted load reductions to account for revisions in TWFs over time, expansion in the list of pollutants with TWFs, or changes in POTW removal.[140] Therefore, comparison of cost-effectiveness values to previous ELGs may not be accurate. EPA recognizes that changes in TWF values affect comparisons across ELGs. For example, in its analysis of the proposed Steam Electric ELGs (U.S. EPA 2013b), EPA calculated the cost-effectiveness of the proposed options using both the current TWFs and an older set of TWFs from 2004 and found that the older TWFs result in lower cost-effectiveness values. For example, the cost-effectiveness of proposed Option 3 for direct dischargers was $44/lb-eq when calculated using the current TWFs, and only $23/lb-eq when calculated using the 2004 TWF values.

[140] The initial list of pollutants for which TWFs are available has increased over time, with approximately 1,900 chemicals currently having TWFs. The cost-effectiveness methodology was originally intended as a “within-an-industry” tool to evaluate different technology options. The set of pollutants and TWFs was consistent at any given point in time, but the analyses did not necessarily look at the full set of pollutants discharged by an industry (if the technology did not address the pollutant). Not until the 2004 304(m) Plan did EPA specifically outline its use of the TWFs in evaluating discharges across industries. However, EPA has not revisited earlier ELG analyses to incorporate new information about pollutants discharged or their TWFs.