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

Table of Contents

List of Abbreviations

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
CCR	Coal combustion residuals
CSAPR	Cross-State Air Pollution Rule
CWA	Clean Water Act
DOE	Department of Energy
EA	Environmental Assessment
ECI	Employment Cost Index
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
GDP	Gross domestic product
IPM	Integrated Planning Model
MATS	Mercury and Air Toxics 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 proposing a regulation that would strengthen 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 proposed 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 proposed 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 Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (TDD) (U.S. EPA, 2013a; DCN SE01964). The TDD provides background on the proposed ELGs; applicability and summary of the proposed 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 proposed ELGs including facility specific compliance cost estimates, pollutant loadings, and non-water quality impact assessment.
- Benefit and Cost Analysis for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (BCA) (U.S. EPA, 2013b; DCN SE03172). The BCA summarizes the societal benefits and costs expected to result from implementation of the proposed ELGs.
- Environmental Assessment for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (EA) (U.S. EPA, 2013c; DCN SE01995). The EA summarizes the environmental and human health improvements that are expected to result from implementation of the proposed ELGs.

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

1.2.1 Steam Electric Plants

The proposed ELGs would establish new requirements for plants within the scope of the existing ELGs for the Steam Electric Power Generating Point Source Category. The ELGs applies to a subset of the electric power industry, namely those plants "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." (40 CFR Part 423.10).

Based on 2009 data from the Department of Energy and additional data EPA obtained from the 2010 Questionnaire for the Steam Electric Power Generating Effluent Guidelines (industry survey; U.S. EPA, 2010a), EPA estimates that there are 1,079 steam electric plants.

Of these, only a subset are likely to incur compliance costs as a result of the proposed ELGs, depending on their operations. As presented in *Table 1-1*, the 1,079 steam electric 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 on the electric generating industry and on steam electric plants subject to the proposed ELGs, see *Chapter 2: Industry Profile*.

Table 1-1: Steam Electric Industry Share of Total Electric Power Generation Existing Parent Entities, Plants, and Capacity in 2009

		Steam Electric Industry[b,c]	
	Total[a]	**Number**	**% of Total**
Parent Entities	2,657	243	9.1%
Plants	5,679	1,079	19.0%
Capacity (MW)	1,121,686	787,108	70.2%

a. Data for total electric power generation industry are from the 2009 EIA-860 database (U.S. DOE, 2009a) and 2009 EIA-861 database (U.S. DOE, 2009b).
b. Steam electric 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 plant owners (for details, see *Chapter 4: Economic Impact Screening Analyses*). EPA estimates at 507 the upper bound number of steam electric plant owners.
Source: U.S. EPA Analysis, 2013; U.S. DOE, 2009a; U.S. DOE, 2009b.

1.2.2 Regulatory Options Considered for the Proposed ELGs

EPA considered eight regulatory options for the proposed ELGs. These options differ in the wastestreams controlled by the regulation, 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 is proposing to revise or establish 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: flue gas desulfurization (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, and nonchemical metal cleaning wastes.

Table 1-2, on the next page, summarizes the eight regulatory options evaluated for the proposed ELGs. After considering these regulatory options, EPA identified Options 3a, 3b, 3 and 4b as the preferred options for regulation of pollutant discharges from existing sources (BAT and PSES). For new sources, EPA identified Option 4 as the preferred option for NSPS and PSNS. The preamble that accompanies the proposed regulation explains the rationale for EPA‟s determination.

Table 1-2: Steam Electric Regulatory Options

Wastestreams	Technology Basis for BAT/NSPS/PSES/PSNS Regulatory Options							
	1	**3a**	**2**	**3b**	**3**	**4a**	**4**	**5**
FGD Wastewater	Chemical Precipitation	BPJ Determination	Chemical Precipitation + Biological Treatment	Chemical Precipitation + Biological Treatment **	Chemical Precipitation + Biological Treatment	Chemical Precipitation + Biological Treatment	Chemical Precipitation + Biological Treatment	Chemical Precipitation + Evaporation
Fly Ash Transport Water	Impoundment (Equal to BPT)	Dry Handling	Impoundment (Equal to BPT)	Impoundment (Equal to BPT)	Dry Handling	Dry Handling	Dry Handling	Dry Handling
Bottom Ash Transport Water	Impoundment (Equal to BPT)	Impoundment (Equal to BPT)	Impoundment (Equal to BPT)	Impoundment (Equal to BPT)	Impoundment (Equal to BPT)	Dry Handling /Closed Loop **	Dry Handling /Closed Loop	Dry Handling /Closed Loop
Combustion Residual Leachate	Impoundment (Equal to BPT)	Impoundment (Equal to BPT)	Impoundment (Equal to BPT)	Impoundment (Equal to BPT)	Impoundment (Equal to BPT)	Impoundment (Equal to BPT)	Chemical Precipitation	Chemical Precipitation
FGMC Wastewater	Impoundment (Equal to BPT)	Dry Handling	Impoundment (Equal to BPT)	Dry Handling	Dry Handling	Dry Handling	Dry Handling	Dry Handling
Gasification Wastewater	Evaporation	Evaporation	Evaporation	Evaporation	Evaporation	Evaporation	Evaporation	Evaporation
Nonchemical Metal Cleaning Wastes	Chemical Precipitation	Chemical Precipitation	Chemical Precipitation	Chemical Precipitation	Chemical Precipitation	Chemical Precipitation	Chemical Precipitation	Chemical Precipitation

** Requirement is subject to applicability threshold. For Option 3b FGD wastewater: Chemical Precipitation + Biological Treatment for units at a facility with a total wet-scrubbed capacity of 2,000 MW and more; BPJ determination for units at a facility with a total wet-scrubbed capacity <2,000 MW. For Option 4a bottom ash transport water: Dry handling/Closed loop for units >400 MW; Impoundment (Equal to BPT) for units ≤400 MW. .

BPT = Best Practicable Control Technology Currently Available.

BPJ = Best Professional Judgment.

Source: U.S. EPA Analysis, 2013

1.2.3 Cost and Economic Analysis Requirements under the Clean Water Act

EPA‟s effluent limitations guidelines and standards for the steam electric industry are proposed 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 proposed ELGs responds 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)[1]:

- Best Practicable Control Technology Currently Available (BPT) (Section 304(b)(1) of the CWA): Traditionally, EPA defines BPT effluent limitations based on the average of the best performances of facilities within the industry, grouped to reflect various ages, sizes, processes, or other common characteristics. EPA may promulgate BPT effluent limits 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. 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 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 pollutants. In general, BAT ELGs represent the best available economically achievable performance of facilities in the industrial subcategory or category. As the statutory phrase intends, EPA considers the technological availability and the ***economic achievability*** in determining what level of control represents BAT (CWA section 301(b)(2)(A), 33 U.S.C. 1311(b)(2)(A)). 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 (CWA section 304(b)(2)(B), 33 U.S.C. 1314(b)(2)(B)). The Agency retains considerable discretion in assigning the weight to be accorded these factors.[2] Generally, EPA determines economic achievability on the basis of the effect of the cost of compliance with BAT limitations on overall industry and subcategory financial conditions. BAT may reflect the highest performance in the industry and 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

[1] For more information, see the preamble that accompanies the proposed 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).

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

pilot plant studies, or foreign plants.[3] BAT may be based upon process changes or internal controls, even when these technologies are not common industry practice.[4]

- Best Conventional Pollutant Control Technology (BCT) (Section 304(b)(4) of the CWA): The 1977 amendments to the CWA required EPA to identify additional levels of effluent reduction for conventional pollutants[5] 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 on July 9, 1986 (51 FR 24974).
- New Source Performance Standards (NSPS) (Section 306 of the CWA). NSPS reflect effluent reductions that are achievable based on the best available demonstrated control technology. Owners of new facilities have the opportunity to install the best and most efficient production processes and wastewater treatment technologies. As a result, NSPS should represent the most stringent controls attainable through the application of the best available demonstrated control technology 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 (CWA section 306(b)(1)(B), 33 U.S.C. 1316(b)(1)(B)).
- Pretreatment Standards for Existing Sources (PSES) (Section 307(b) of the CWA). 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. 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). Pretreatment standards are designed to prevent the discharge of any pollutant into a POTW that may interfere with, pass through, or may otherwise be incompatible with the POTW. EPA promulgates PSNS based on best available demonstrated control technology for new sources. New indirect dischargers have the opportunity to incorporate into their facilities the best available demonstrated technologies. The Agency typically considers the same factors in promulgating PSNS as it considers in promulgating NSPS.

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

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).

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[3] 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).
[4] 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).
[5] Section 304(a)(4) of the CWA designates the following as conventional pollutants: BOD_5, total suspended solids (TSS), fecal coliform, pH, and any additional pollutants defined by the Administrator as conventional. The Administrator designated oil and grease as an additional conventional pollutant on July 30, 1979 (44 FR 44501; 40 CFR 401.16).

1.2.4 Analyses Performed in Support of the Proposed ELGs and Report Organization

EPA performed the following analyses in support of the proposed ELGs; some of these analyses are discussed in the *Benefit and Cost Analysis for Proposed Steam Electric Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (BCA)* document:

- **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 proposed ELGs using the Integrated Planning Model (IPM) and provides insight into the effects that compliance requirements on steam electric plants would have on the steam electric industry and on national electricity markets.
- **Assessment of potential electricity price effects** (*Chapter 6*), which looks at the impacts of compliance in terms of increased electricity prices for households and for other consumers of electricity.
- **Analysis of employment effects** (*Chapter 7*), which assesses national-level changes in employment in the steam electric industry.
- **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.
- **Assessment of total social costs** (discussed in separate *BCA* document).
- **Analysis of benefits** (discussed in separate *BCA* document).
- **Comparison of social costs and benefits** (discussed in separate *BCA* document).

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 plants subject to the proposed ELGs (*Chapter 2*). The profile provides information about the operating characteristics of the electric power industry as a whole and of steam electric plant universe in particular.

Finally, several appendices provide supporting information:

- *Appendix A: References* provides detailed information on sources cited in the text.
- *Appendix B: Sensitivity Analysis* summarizes results of four alternate analysis scenarios to evaluate the sensitivity of results to different assumptions: (1) incorporating projected installations of air pollution control through 2020; (2) applying BAT and PSES requirements to all generating units regardless of the type or generating capacity; (3) assuming the immediate implementation of control technologies upon renewal of a plant‟s National Pollutant Discharge Elimination System (NPDES)

permit following rule promulgation; and (4) assuming that plants pass through a fraction of their compliance costs to electricity consumers.

- *Appendix C: IPM* provides an overview of IPM V4.10, which is the basis of the Market Model Analyses for the proposed ELG regulatory options discussed in *Chapter 5*.
- *Appendix D: Cost Effectiveness* describes EPA‟s analysis of the cost-effectiveness of the proposed ELGs. It also compares the cost-effectiveness of the proposed 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 that industry that is subject to the proposed ELGs (steam electric 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 proposed 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 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 proposed 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 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 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 2012.
- *Section 2.7* provides a glossary of key terms used throughout the chapter.

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, 2012b):

- The <u>generation</u> 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 regulation. 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, 2012b):

- 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 proposed ELGs to a given plant. As defined in 40 CFR Part 423.10, the proposed ELGs apply to plants "primarily engaged in the generation of electricity for distribution and sale 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." 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, 2012b):

- Electric utility: 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.
- Nonutility: 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 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, 2012b):

- 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.

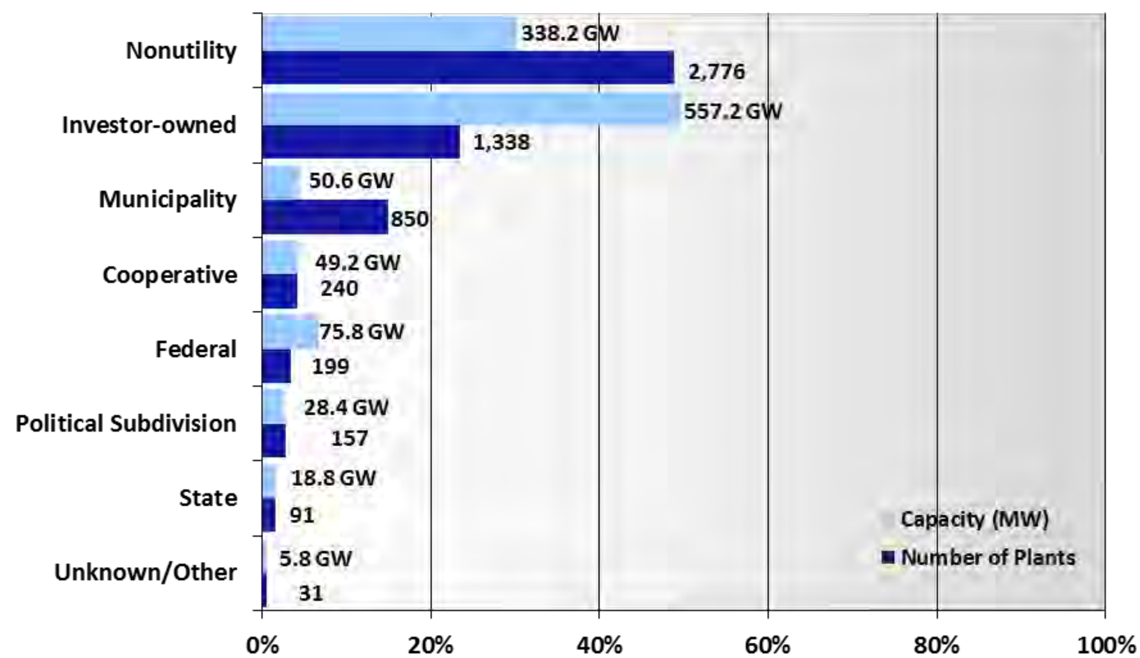
The type of entities owning and operating electric power plants is an important consideration for assessing the impact of the proposed ELGs on steam electric plants and electricity consumers, as it is one of the factors affecting the recovery of any increases in production costs resulting from compliance with the proposed 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 plants. A likely more important factor is the regulatory environment in the state where a steam electric 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 2009, 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, 2009 EIA-860, and 2009 EIA-861 databases, and additional research (U.S. DOE, 2006; U.S. DOE, 2009a; U.S. DOE, 2009b; U.S. EPA, 2010a).[6] The horizontal axis also presents the

6 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.

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 2009.[7] The chart shows that nonutilities account for the largest percentage of plants (49 percent) but represent only 30 percent of total U.S. generating capacity. Investor-owned utilities operate the second largest percentage of plants at 24 percent and account for 40 percent of total U.S. capacity.

Figure 2-1: Distribution of Plants and Nameplate Capacity by Ownership Type, 2009



Source: U.S. DOE, 2006; U.S. DOE, 2009a; U.S. DOE, 2009b; U.S. EPA, 2010a

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;[8] it reflects a reduction in capacity due to electricity use for station service or auxiliaries. *Net winter capacity* is the maximum output that a generating unit can supply to *system load* at the time of *winter* peak

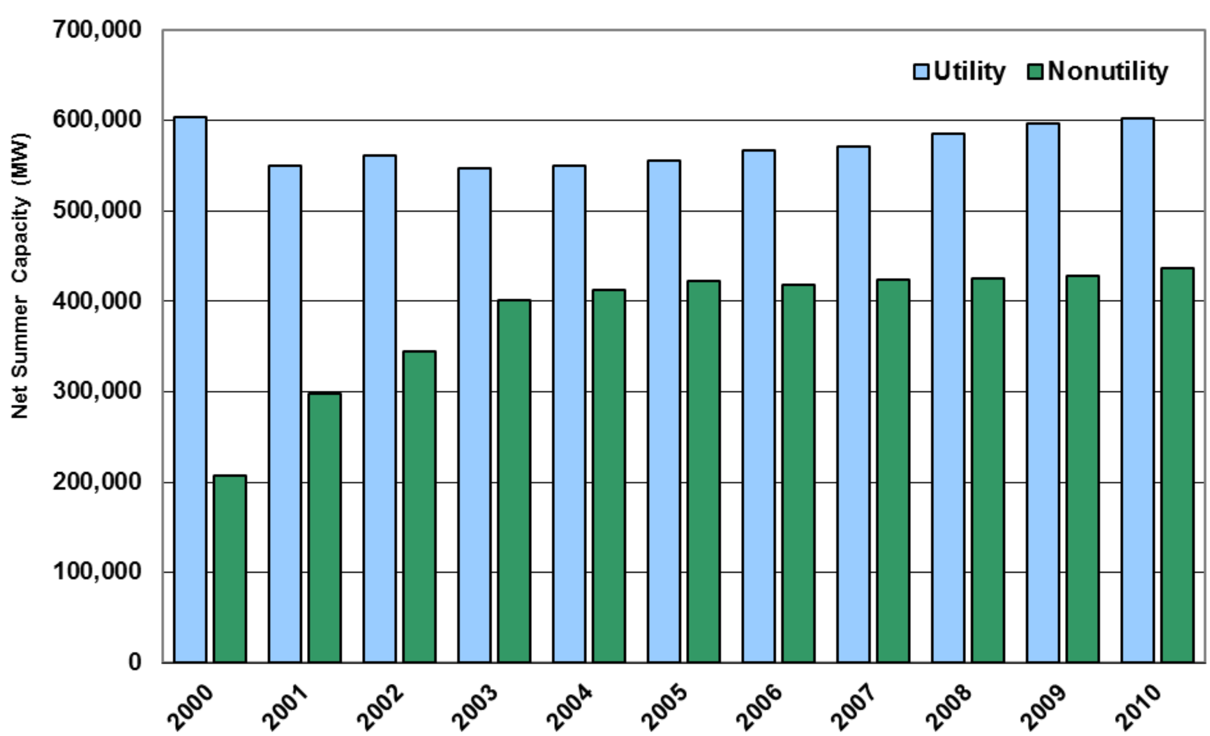
[7] EPA also included three steam electric plants that the Agency identified in the steam electric industry survey, but that were not included in the existing generator universe in the 2009 EIA-860 database.

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

demand;[9] it also reflects a reduction in capacity due to electricity use for station service or auxiliaries. Because, in most of the United States, summer peak demand exceeds winter peak demand, aggregate net summer capacity exceeds net winter capacity (U.S. DOE, 2012b).

In 2010, utilities owned and operated the majority of *net summer capacity* (58 percent) in the United States, with nonutilities owning the remaining 42 percent. Nonutility ownership of net summer capacity increased substantially in the last few years, following the passage of state legislation aimed at increasing competition in the electric power industry. Nonutility ownership of net summer capacity increased by 111 percent between 2000 and 2010, compared with a decrease in utility ownership of net summer capacity of 0.4 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 811,719 MW in 2000 to 1,039,062 MW in 2010 (see *Figure 2-2*).

Figure 2-2: Net Summer Capacity (MW), 2000 to 2010



Source: U.S. DOE, 2011b

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, 2012a).

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

As presented in *Table 2-1*, total net electricity generation in the United States for 2010 was 4,125 TWh.[10] In 2010, coal accounted for the largest share of total electricity generation (45 percent), despite a 6 percent decline over the 11-year period of 2000 through 2010. In terms of the share of the total generation, coal was followed by natural gas (24 percent) and nuclear power (20 percent). Other energy sources accounted for comparatively smaller shares of total generation, with hydropower representing 6 percent; renewable energy, 4 percent; and petroleum, 0.3 percent (see *Figure 2-3)*.

In 2010, utility-owned plants accounted for 60 percent of total electricity generation, with nonutility-owned plants accounting for the remaining 40 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 2000 through 2010, total net generation increased by approximately 8 percent. This growth was driven by increases in nuclear power-, natural gas-, renewables-fueled electricity generation and electricity generation from "other" fuels. During the same time, coal-, hydropower-, petroleum- fueled electricity generation and electricity generation from other gases declined, with petroleum recording the largest percent decline of 67 percent.

Between 2000 and 2010, the amount of electricity generated by utilities declined by 18 percent while that generated by nonutilities more than doubled. This trend is expected to continue in the coming years, as more plants are built by nonutility power producers or purchased from traditional integrated utilities. Comparing 2000 and 2010 values, across all fuel-source categories, utilities generated a larger share of their electricity using natural gas (a 35 percent increase) and renewables (a 700 percent increase) even as their overall generation declined. For nonutilities, the largest percent increase in electricity generation (689 percent) occurred for nuclear power, followed by "other" fuels and natural gas. In terms of absolute quantity of generated electricity, the largest increase for nonutilities occurred for natural gas followed by coal.

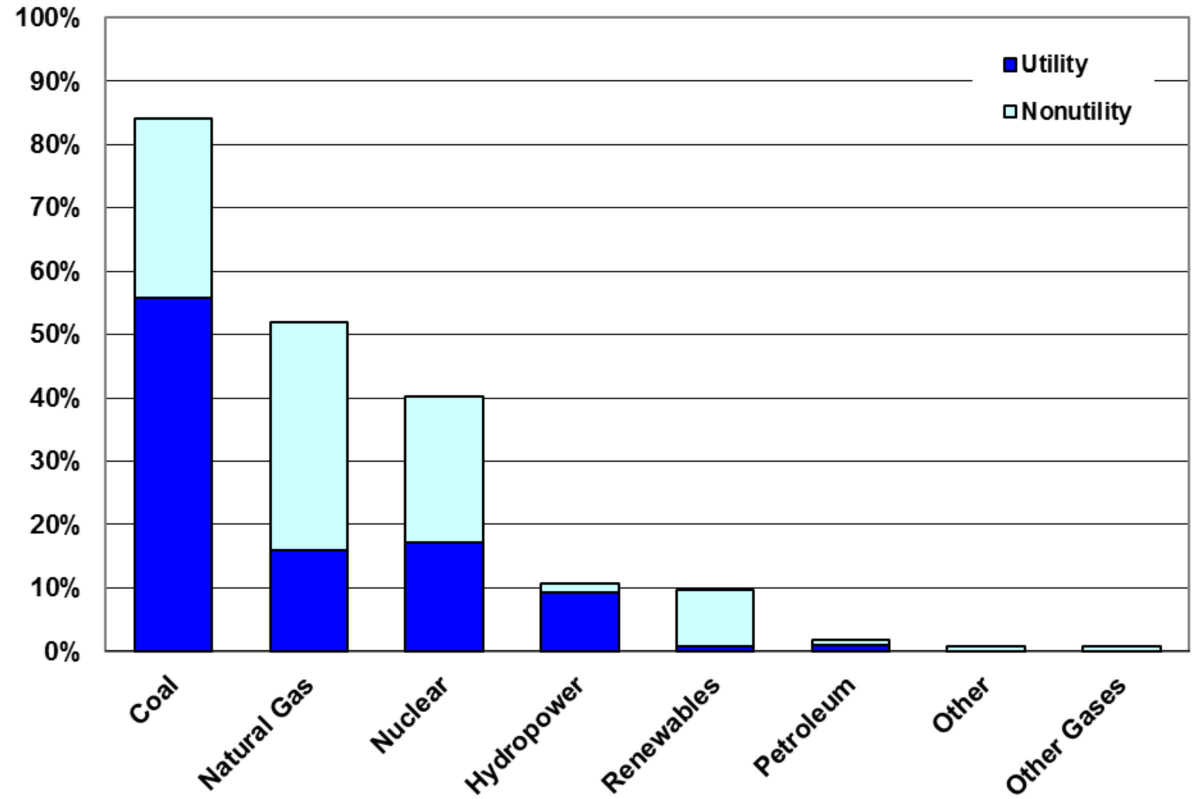
Table 2-1: Net Generation by Energy Source and Ownership Type, 2000 to 2010 (TWh)

	Utilities			Nonutilities			Total		
Energy Source	**2000**	**2010**	**% Change**	**2000**	**2010**	**% Change**	**2000**	**2010**	**% Change**
Coal	1,697	1,378	-18.8%	270	469	74.0%	1,966	1,847	-6.1%
Hydropower	248	232	-6.7%	22	23	5.6%	270	255	-5.7%
Nuclear	705	425	-39.8%	48	382	688.5%	754	807	7.0%
Petroleum	72	26	-63.9%	39	11	-71.8%	111	37	-66.7%
Natural Gas	291	393	35.1%	310	595	91.8%	601	988	64.3%
Other Gases	0	0	NA	14	11	-19.3%	14	11	-18.9%
Renewables[a]	2	18	700.0%	79	149	89.7%	81	167	106.6%
Other[b]	0	0	NA	5	12	158.5%	5	13	168.2%
Total	**3,015**	**2,472**	**-18.0%**	**787**	**1,653**	**110.2%**	**3,802**	**4,125**	**8.5%**

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, 2011b

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

Figure 2-3: Percent of Electricity Generation by Primary Fuel Source and Plant Ownership Type, 2010



Source: U.S. DOE, 2011b

2.3.3 Geographic Distribution

Electricity is a commodity that 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), also known as Electric Reliability Council of Texas (ERCOT).[11]

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. This voluntary organization was formed in 1968 by electric utilities, following a 1965 blackout in the Northeast. 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.[12] 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:[13]

- 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.)

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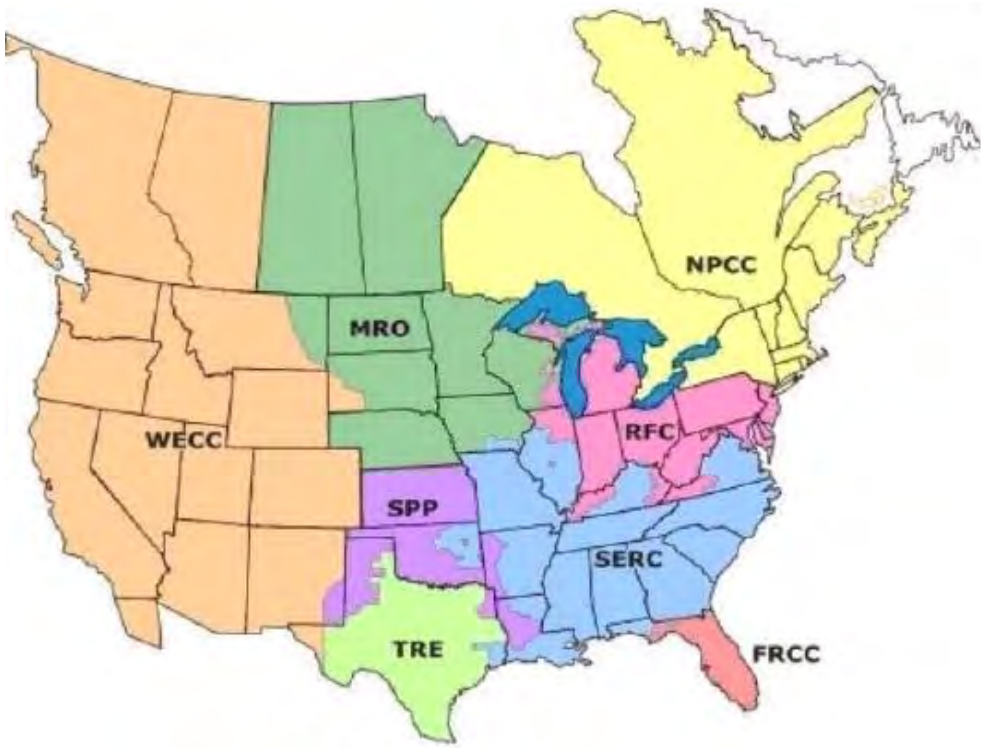
11 Texas Reliability Entity, Inc was established in 2006 to ensure the reliability of the bulk power system in the Electric Reliability Council of Texas (ERCOT) NERC region. Subsequently, this NERC region became known as TRE. For this analysis, we refer to this region as ERCOT.

12 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.

13 Some NERC regions have been re-defined/re-named over the past few years; the NERC region definitions used in the proposed ELG analyses vary by analysis depending on which region definition aligns better with the data elements underlying the analysis. 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.

b Texas Reliability Entity, Inc was established in 2006 to ensure the reliability of the bulk power system in the Electric Reliability Council of Texas (ERCOT) NERC region. Subsequently, this NERC region became known as TRE. For this analysis, we refer to this region as ERCOT.

Source: U.S. DOE, 2012c.

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 proposed 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 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 proposed regulation 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, 2009

	Plants		Capacity	
NERC Region	**Number**	**% of Total**	**Total MW**	**% of Total**
ASCC	123	2.2%	2,212	0.2%
FRCC	129	2.3%	64,621	5.7%
HICC	42	0.7%	2,805	0.2%
MRO	753	13.3%	61,320	5.5%
NPCC	722	12.7%	79,475	7.1%
RFC	930	16.4%	251,939	22.4%
SERC	923	16.2%	292,306	26.0%
SPP	302	5.3%	66,540	5.9%
ERCOT	252	4.4%	95,514	8.5%
WECC	1,506	26.5%	207,229	18.4%
TOTAL	**5,682**	**100.0%**	**1,123,959**	**100.0%**

Source: U.S. DOE, 2009a

2.4 Steam Electric Plants

The proposed ELGs would establish new requirements for plants within the scope of the existing ELGs for the Steam Electric Power Generating Point Source Category. These are plants that are "primarily engaged in the generation of electricity for distribution and sale 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." (40 CFR Part 423.10). Based on the data collected through the industry survey, EPA identified 1,079 steam electric plants.[14]

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

- **Ownership type**: *Section 2.4.1* reviews the distribution of steam electric 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 plants.
- **Plant size**: *Section 2.4.3* reviews the size of steam electric plants based on generating capacity.
- **Geographic distribution**: *Section 2.4.4* reports the geographic distribution of steam electric 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

[14] The industry survey gathered information from a sample of 733 plants, of which 680 respondents are steam electric plants. After removing plants that did not operate steam electric power generating units in 2009 and applying sample weights, EPA estimates the total universe of existing steam electric plants subject to 40 CFR part 423 to be 1,079 plants. 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 proposed ELGs on State, local, and tribal governments in accordance with the Unfunded Mandates Reform Act (UMRA) of 1995 (see *Chapter 9: UMRA*).[15]

Table 2-3 reports the number of parent entities, plants, and capacity by ownership type for the total industry and for the subset of 1,079 steam electric plants (for details on determination of parent entities for steam electric plants, see *Chapter 4: Economic Impact Screening Analyses*). Overall, EPA estimates that steam electric plants account for between 9 percent (lower bound) and 19 percent (upper bound) of all parent entities, 19 percent of all electric power plants, and 70 percent of total electric power sector capacity.[16,17] The majority of steam electric plants (63 percent of all steam electric plants) are owned by investor-owned utilities, while nonutilities make up the second largest category (14 percent of all steam electric plants). In terms of steam electric capacity, investor-owned utilities account for the largest share (72 percent) of total steam electric capacity.

Table 2-3: Existing Steam Electric 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	30	12.3%	52	10.3%	67	6.2%	36,006	4.6%
Federal	2	0.8%	4	0.8%	15	1.4%	30,570	3.9%
Investor-owned	97	39.9%	244	48.1%	680	63.0%	563,772	71.6%
Municipality	65	26.7%	101	20.0%	122	11.3%	38,114	4.8%
Nonutility	35	14.4%	73	14.4%	150	13.9%	86,952	11.0%
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%	5,402	0.7%
Steam Electric Total	**243**	**100.0%**	**507**	**100.0%**	**1,079**	**100.0%**	**787,108**	**100.0%**

a. Numbers may not add up to totals due to independent rounding.
b. Ownership information on steam electric 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 plants. For details see *Chapter 4*.
d. Steam electric plant counts and capacity were calculated on a sample-weighted basis. For details on sample weights, see *TDD*.
Source: U.S. EPA Analysis, 2013; U.S. DOE, 2006; U.S. DOE, 2009a; U.S. DOE, 2009b; U.S. EPA, 2010a

2.4.2 Ownership Type

EPA estimates that between 34 percent and 40 percent of entities owning steam electric 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) business size criteria.[18,19] Small entities owning steam electric plants represent between 9 percent and 15 percent of all small entities in the electric power industry.

15 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 proposed ELG, it is not a sole or a deciding factor.

16 EPA estimates that there are 5,682 electric power plants in the United States; these plants are owned by 2,657 entities and account for 1,123,959 MW of total generating capacity.

17 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 2009 EIA-860 database (U.S. DOE, 2009a).

18 EPA determined entity size for industry-wide parent entities in two steps. The Agency first used utility/operator-level electricity sales data from the 2009 EIA-861 database (U.S. DOE, 2009b) and, if sales data were not available, electricity net generation data from the 2009 EIA-906/920/923 database (U.S. DOE, 2009c) to determine utility/operator size using the 4,000,000 MWh SBA size criterion. To account for the fact that (1) utility/operator may

The size distribution of parent entities owning steam electric 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 1,079 steam electric plants, 189 (18 percent) are owned by small entities (*Table 2-5*). Investor-owned utilities own the largest share of steam electric plants owned by small entities, at 46 percent, while cooperatives, investor-owned, nonutilities, and other political subdivisions own the remaining 54 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 plants, see *Chapter 4* and *Chapter 8*.

Table 2-4: Parent Entities of Steam Electric Plants by Ownership Type and Size (assuming two different ownership cases)[a,b]

	Lower bound estimate of number of entities owning steam electric plants				Upper bound estimate of number of entities owning steam electric plants			
Ownership Type	**Small**	**Large**	**Total**	**% Small**	**Small**	**Large**	**Total**	**% Small**
Cooperative	13	17	30	43.3%	21	31	52	40.7%
Federal	0	2	2	0.0%	0	4	4	0.0%
Investor-owned	27	70	97	27.8%	64	180	244	26.3%
Municipality	37	28	65	56.9%	46	55	101	45.3%
Nonutility	18	17	35	51.4%	34	39	73	46.8%
Other Political Subdivision	2	10	12	16.7%	4	26	30	14.2%
State	0	2	2	0.0%	0	2	2	0.0%
Total	**97**	**146**	**243**	**39.9%**	**170**	**337**	**507**	**33.5%**

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 plants see *Chapter 4* and *Chapter 8*.

Source: U.S. EPA Analysis, 2013; U.S. DOE, 2006; U.S. DOE, 2009a; U.S. DOE, 2009b; U.S. DOE, 2009c; U.S. EPA, 2010a

Table 2-5: Steam Electric Plants by Ownership Type and Size

	Number of Steam Electric Plants[a,b,c]			
Ownership Type	**Small**	**Large**	**Total**	**% Small**
Cooperative	22	45	67	33.3%
Federal	0	15	15	0.0%
Investor-owned	87	593	680	12.8%
Municipality	47	75	122	38.5%
Nonutility	29	121	150	19.3%
Other Political Subdivisions	4	36	41	10.6%
State	0	5	5	0.0%
Total	**189**	**890**	**1,079**	**17.5%**

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, 2013; U.S. DOE, 2009a; U.S. DOE, 2009b; U.S. EPA, 2010a

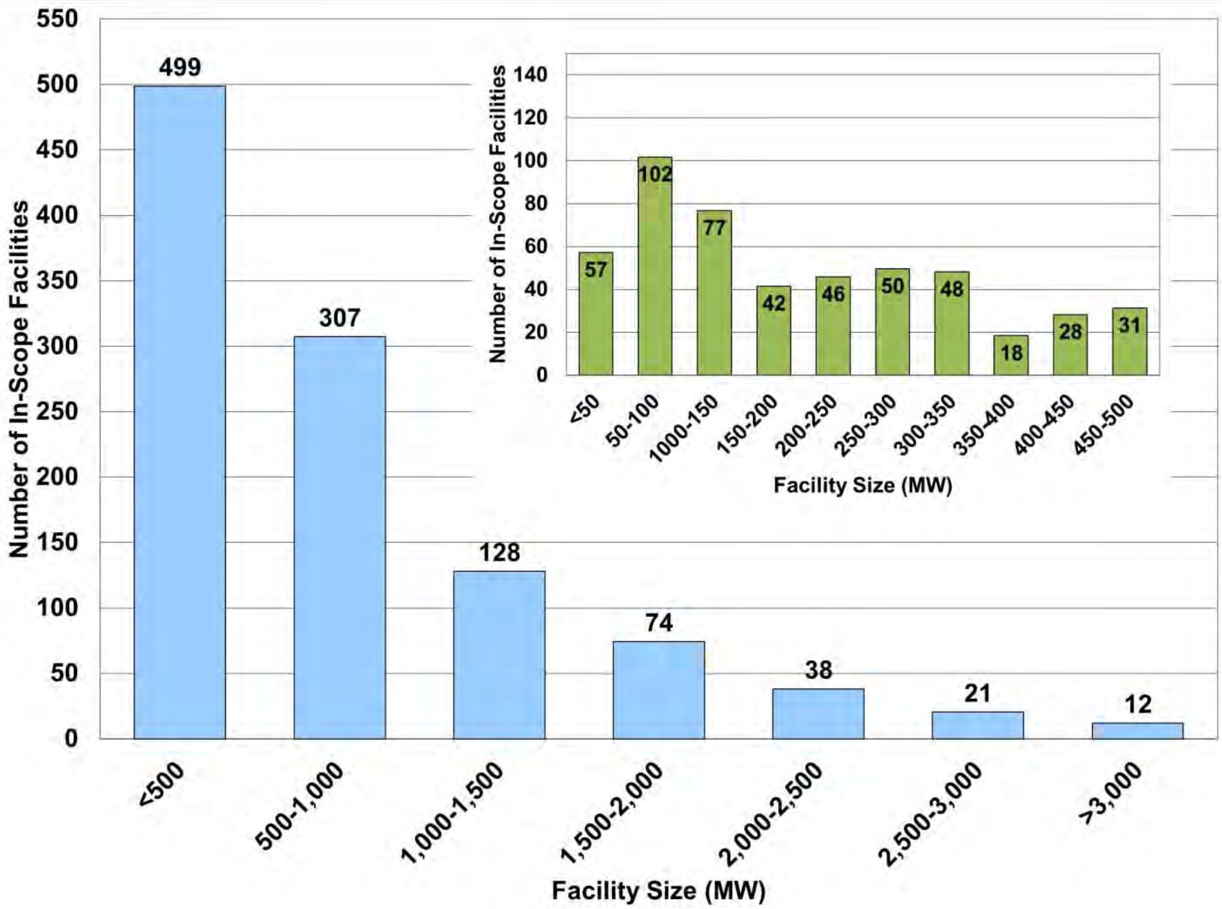
not be the highest-level domestic parent and (2) according to SBA, size determination for entities of certain ownership types should be based on criterion other than total electric output, EPA then adjusted counts of small utilities/operators estimated in the first step. The Agency made that adjustment based on the observed relationship between electric output-based size determination and size determination based on the appropriate SBA criterion done for steam electric universe.

19 EPA estimates that 1,140 out of the total 2,657 entities (43 percent) that own electric power plants are small.

2.4.3 Plant Size

EPA also assessed the size of steam electric 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 plants (75 percent) have a capacity of less than 1,000 MW, 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 plants with generating capacity less than 500 MW, 57 steam electric plants had a capacity less than 50 MW.

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



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

b. Plant counts and capacity values are sample-weighted estimates.

Source: U.S. EPA Analysis, 2013; U.S. DOE, 2009a; U.S. EPA, 2010a

2.4.4 Geographic Distribution of Steam Electric Plants

To assess the potential reliability impact of the proposed ELGs, EPA assessed the distribution of steam electric 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 plants and their capacity. Steam electric plants are concentrated in the RFC and SERC regions (21 percent and 20 percent, respectively); these two regions account for a majority of the steam electric capacity in the United States (25 percent and 26 percent, respectively).

Table 2-6: Steam Electric Plants and Capacity by NERC Region, 2009[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%	62,637	8.0%
HICC	12	1.1%	1,418	0.2%
MRO	87	8.1%	38,353	4.9%
NPCC	104	9.6%	37,822	4.8%
RFC	230	21.3%	193,641	24.7%
SERC	218	20.2%	207,213	26.4%
SPP	92	8.6%	62,352	7.9%
ERCOT	85	7.9%	65,991	8.4%
WECC	194	18.0%	115,427	14.7%
TOTAL	**1,079**	**100.0%**	**784,912**	**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, 2013; U.S. DOE, 2009a; U.S. EPA,2010a

2.5 Industry Trends

Deregulation, along with several environmental regulations and programs, has had a significant impact on the electric power industry in recent years. *Section 2.5.1* discusses the current status of industry deregulation, *Section 2.5.2* discusses air emissions regulations, *Section 2.5.3* discusses renewable portfolio standards, and *Section 2.5.4* discusses greenhouse gas emissions regulations, all of which have affected and/or will affect the electric power industry.

2.5.1 Current Status 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).[20] 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 framework). As a result of deregulation, competitive market forces set prices for generated electricity.

[20] 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.

> 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).[21]

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[22] 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 3,740 plants (66 percent of all electric power generating plants in the United States) and 710 GW of generating capacity (63 percent of total generating capacity in the United States) (U.S. DOE, 2009a; 2010a). *Figure 2-6* provides a national map of the status of electricity restructuring.

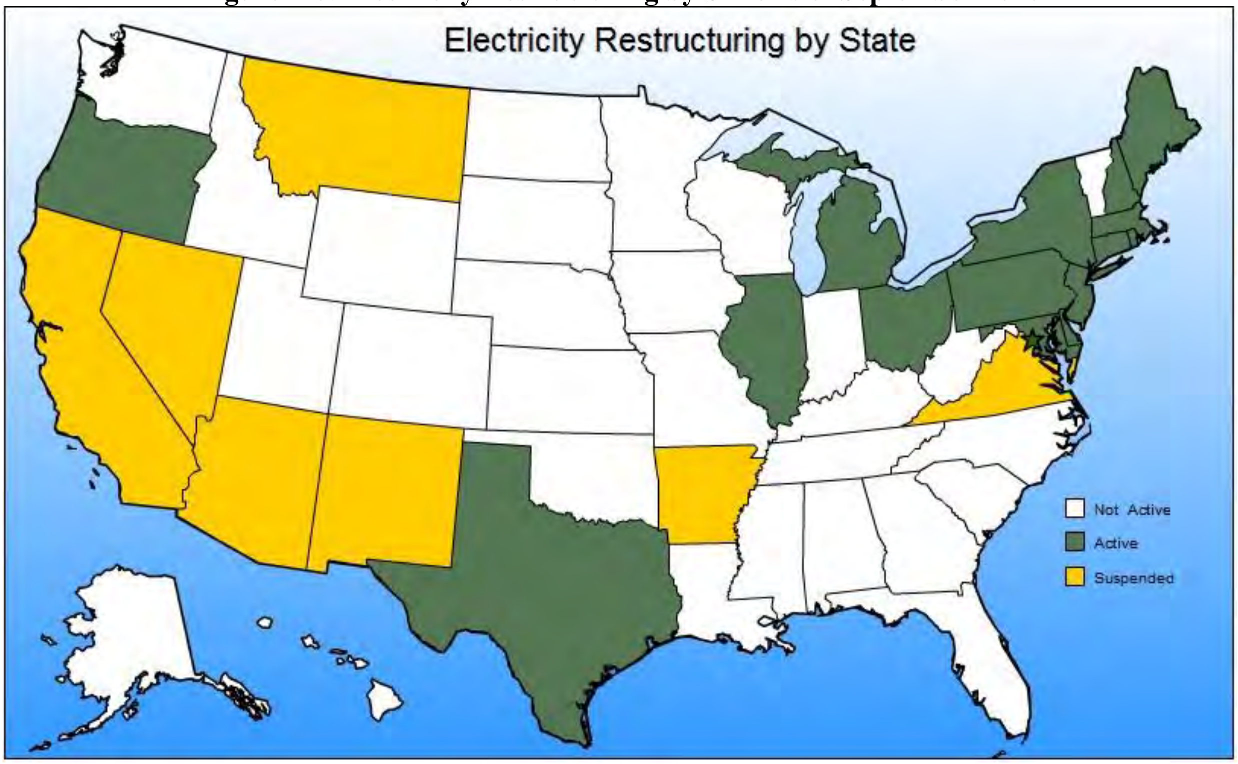
The state of restructuring of the electric power industry is an important factor to consider when assessing the impact of the proposed ELGs on steam electric plants and electricity consumers, as discussed in *Chapter 4: Economic Impact Screening Analyses* and *Chapter 7:Electricity Price Effects*. In particular, the degree of competition affects, although not solely, the ability of steam electric plants to pass cost increases to consumers via electricity rate increases, and consequently, affects their profitability and business viability. Most steam electric plants (671 out of 1,079 or 62 percent) are located in states with regulated electricity generation markets; these plants account for 65 percent of total generating capacity (510 GW out of 787 GW) and total generation (2,262 TWh out of 3,482 TWh) at steam electric 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

21 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.

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

market mechanisms used to sell electricity.[23] The other 408 steam electric plants (38 percent) are located in states where electricity generation is deregulated and cost recovery is less certain; these plants account for approximately 277 GW of total generating capacity (35 percent) and 1,220 TWh of total generation (35 percent) at steam electric plants (U.S. DOE, 2009a).[24,25]

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



Source: U.S. DOE, 2010a

2.5.2 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,

23 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.

24 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 proposed ELG. See *TDD* for further discussion of the sample weights used in this analysis.

25 Capacity values are from the 2009 EIA-860 database. EPA calculated generation values as a 3-year average (2007-2009) 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.

including increased use of lower pollution fuels, repowering of existing production capacity (e.g., converting natural gas-based steam capacity to a more energy efficiency 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 plants by introducing new wastestreams (e.g., installation of a flue gas desulfurization system) or changing the pollutants loads in plant wastewater.

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).

Similar to the Acid Rain Program, the Clean Air Interstate Rule (CAIR) was promulgated to further reduce SO_2 and NOx emissions in 27 eastern states and the District of Columbia through an allowance trading program. On July 11, 2008, the U.S. Court of Appeals for the D.C. Circuit ruled to vacate CAIR. However, on December 23, 2008, the U.S. Court of Appeals issued a new ruling that repealed the vacatur and instead, remanded CAIR, noting that: "allowing CAIR to remain in effect until it is replaced by a rule consistent with our opinion would at least temporarily preserve the environmental values."[26] EPA was tasked with modifying CAIR to address the issues raised by the Court in its July 11th decision (U.S. EPA, 2010b).

Other rulemakings are based in part on the expected emissions reductions from CAIR.[27] Promulgated in 2005, CAIR established Phase I caps for NOx and SO_2 for 2009 and 2010, respectively, and Phase II caps for NOx and SO_2 for 2015. For SO_2 allowances, CAIR allocated the allowances that are used within the Acid Rain Program. However, since a NOx trading program was not in place in the Acid Rain Program, EPA provided new NOx emission allowances under CAIR. Each of the 28 eastern states and the District of Columbia were allowed to achieve emissions reductions by their own selected method. Most are expected to achieve the required levels by mandating reduced emissions from the power generation sector (U.S. EPA, 2009a).

On July 6, 2011, EPA promulgated the Cross-State Air Pollution Rule (CSAPR) to replace CAIR. The rule required 27 states in the eastern half of the United States to significantly improve air quality by reducing power plant emissions of sulfur dioxide, nitrogen oxides (NOx) and/or ozone-season NOx that cross state lines and significantly contribute to ground-level ozone and/or fine particle pollution problems in other states. Subsequently, the Agency issued a supplemental rule in the CSAPR ozone-season NOx program. The emissions of sulfur dioxide, NOx and ozone-season NOx addressed by these rules react in the atmosphere to form PM2.5 and ground-level ozone and are transported long distances, making it difficult for a number of states to meet the national clean air standards that Congress directed EPA to establish to protect public health. (U.S. EPA 2011b). EPA‟s Cross-State Air Pollution Rule (CSAPR) was scheduled to replace EPA‟s Clean Air Interstate Rule (CAIR) starting January 1, 2012. However, on December 30, 2011, the U.S. Court of Appeals for the D.C. Circuit stayed CSAPR pending judicial review and left CAIR in place. On August 21,

[26] State of North Carolina v. EPA, Case No. 05-1244, (D.C.Cir. 2003)

[27] Emissions reductions under the national ambient air quality standards (NAAQS) and the new source review (NSR) program are dependent in part to emissions reductions from CAIR.

2012 the Court issued an opinion vacating CSAPR and again leaving CAIR in place pending development of a valid replacement. On March 29, 2013, the United States filed a petition asking the Supreme Court to review the D.C. Circuit"s opinion. Nevertheless, as explained above, CAIR remains in effect at this time. In light of the continuing uncertainty on CAIR and CSAPR, EPA does not believe it would be appropriate or possible at this time to adjust emission projections on the basis of speculative alternative emission reduction requirements in 2020. EPA expects that the decision vacating CSAPR and leaving CAIR in place has a minimal effect on the results of the analysis conducted in support of the proposed ELGs (see *Chapter 5: Electricity Market Analyses*).

Also building off CAIR, the Clean Air Visibility Rule (CAVR), finalized on June 15, 2005, requires emission controls to reduce SO_2 and NOx emissions using Best Available Retrofit Technology (BART) for industrial and power generation plants.

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). 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.

2.5.3 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 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. [28] Four of the six states that most recently adopted electric portfolio standards chose to enact CES as opposed to RPS (PCGCC, 2011).

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

2.5.4 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[29] have adopted CO_2 performance standards while another 11 states[30] have enacted utility sector cap and trade programs (PCGCC, 2012). Both the Northeast Regional Greenhouse Gas Initiative (RGGI)[31] and the Western Climate Initiative (WCI)[32] 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.[33] 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. On December 23, 2010, EPA entered a settlement agreement to issue rules that will address greenhouse gas emissions for fossil fuel-fired power plants. Following this agreement, EPA published the Proposed Greenhouse Gas New Source Performance Standard for Electric Generating Units on April 13, 2012 (U.S. EPA, 2012a). 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. EPA is evaluating the public comments received on the proposal and has not determined a schedule at this time for taking final action on the proposed rule.

2.6 Industry Outlook

This section presents a summary of forecasts from the Annual Energy Outlook 2012 (AEO2012) (U.S. DOE, 2012d).

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 AEO2012 (U.S. DOE, 2012d). AEO2012 contains projections of future market conditions through the year 2035, 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 January 2012.

Electricity Demand

EIA projects electricity demand to grow by approximately 0.7 percent annually between 2010 and 2035.[34] This growth will be driven by an estimated 1.0 percent annual increase in commercial sector demand for

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

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

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

32 The WCI consists of Arizona, California, Montana, New Mexico, Oregon, Utah, and Washington.

33 Massachusetts vs. Environmental Protection Agency, 549 U.S. 497

34 With the exception of the market analyses discussed in *Chapter 5*, in analyzing the economic effects of the proposed 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 2014 as they did on average during

electricity stemming from increases in demand for office equipment and growth in commercial floor space in the service industries. Residential demand is expected to increase by 0.7 percent annually over the same forecast period; this projected increase is driven by a growing number of U.S. households, greater disposable income, and continued population shifts to warmer climates with greater cooling requirements; however, energy efficiency improvements offset this increased demand to a degree. The industrial sector has seen declining electricity demand growth rates since 2000 due to increased competition from foreign manufacturers and a shift by domestic manufacturers toward producing less energy-intensive goods. EIA expects this trend in the industrial sector to continue with an expected annual growth of only 0.1 percent. While electricity demand in the transportation sector is currently small, the EIA projects a strong average annual growth rate of 4.8 percent between 2010 and 2035, driven by increased future sales of electric plug-in light duty vehicles.

Capacity Retirements

According to AEO2012, fossil fuel-fired capacity will make up the largest share of total retired capacity. Overall, EIA forecasts that 81.9 GW of total fossil-steam capacity will retire between 2010 and 2035, including 20.3 GW of oil and natural gas fired steam capacity. EIA projects that coal will have the largest share of capacity retirements with an expected 49.0 GW of retired capacity by 2035 (55.4 percent of total retirements). An additional 6.1 GW of nuclear plant capacity are also expected to retire during this period.

Capacity Additions

According to AEO2012, 235 GW of new generating capacity will be needed between 2011 and 2035 due to the estimated growth in electricity demand and the need to offset the retirement of 88 GW of existing capacity. These capacity requirements are expected to be met by natural gas, renewable energy, coal, and nuclear power sources – in order of expected contribution. Of the new capacity projected to come on line between 2011 and 2035, approximately 60 percent is projected as natural gas-fired capacity, 29 percent is expected to be fueled by renewables, 7 percent by coal-fired plants, and 4 percent by nuclear energy. The increase in renewable capacity results in part from RPS, as described in *Section 2.5.3*.

Electricity Generation

According to AEO2012, 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 throughout the forecast period. Natural gas-fired power plants are expected to make up much of the new capacity over the next ten years, and coal-fired generation is projected to decrease between 2010 and 2035, reducing its share of total generation from 45 percent to an estimated 38 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 24 percent to 28 percent. The share of total generation from renewable power sources is expected to increase from 10 percent in 2010 to 15 percent of total generation in 2035. Nuclear power generation, however, is expected to decrease from 20 percent to 18 percent as a share of total generation.

Electricity Prices

According to AEO2012, between 2010 and 2035, average annual electricity prices are expected to rise by 3 percent. Until 2021, electricity prices are expected to fall due to lower fuel prices but are then expected to rebound in response to increased demand for energy. Although transmission and distribution costs are

2007-2009. In the market analyses conducted using the Integrated Planning Model (IPM) (see *Chapter 5*), demand growth assumptions are based on AEO 2010.

expected to decrease over time, rising fuel costs after 2020 are expected to result in higher electricity prices; average end-use electricity prices are expected to be 10.1 cents per kilowatt hour in 2035 ($2010).

2.7 Glossary

Base Load: A baseload generating unit is normally used to satisfy all or part of the minimum or base load of the system and, as a consequence, produces electricity at an essentially constant rate and runs continuously. Baseload units are generally the newest, largest, and most efficient of the three types of units. (http://www.eia.doe.gov/cneaf/electricity/page/prim2/chapter2.html)

Combined Cycle Turbine: An electric generating technology in which electricity is produced from otherwise lost waste heat exiting from one or more gas (combustion) turbines. The exiting heat is routed to a conventional boiler or to heat recovery steam generator for utilization by a steam turbine in the production of electricity. This process increases the efficiency of the electric generating unit.

Distribution: The portion of an electric system that is dedicated to delivering electric energy to an end user.

Electricity Available to Consumers: Power available for sale to customers. Approximately 8 to 9 percent of net generation is lost during the transmission and distribution process.

Gas Turbine: A gas turbine typically consisting of an axial-flow air compressor and one or more combustion chambers, where liquid or gaseous fuel is burned and the hot gases are passed to the turbine. The hot gases expand to drive the generator and are then used to run the compressor.

Generation: The process of producing electric energy by transforming other forms of energy. Generation is also the amount of electric energy produced, expressed in watthours (Wh).

Gross Generation: The total amount of electric energy produced by the generating units at a generating station or stations, measured at the generator terminals.

Hydroelectric Generating Unit: A unit in which the turbine generator is driven by falling water.

Intermediate load: Intermediate-load generating units meet system requirements that are greater than baseload but less than peakload. Intermediate-load units are used during the transition between baseload and peak load requirements. (http://www.eia.doe.gov/cneaf/electricity/page/prim2/chapter2.html)

Internal Combustion Engine: An internal combustion engine has one or more cylinders in which the process of combustion takes place, converting energy released from the rapid burning of a fuel-air mixture into mechanical energy. Diesel or gas-fired engines are the principal fuel types used in these generators.

Kilowatt-hours (kWh): A measure of electric energy generated or consumed. The amount of energy generated from one Kilowatt of fully utilized capacity during one hour. A *Megawatt-hour* (MWh) is also an energy measure and equals 1,000 Kilowatt-hours.

Load: Refers to either demand for electricity or total electricity generated.

Megawatt (MW): Unit of power equal to one million watts. A watt is a measure of *power*, or the potential to produce or consume electricity (or other energy).

Nameplate Capacity: The amount of electric power delivered or required for which a generator, turbine, transformer, transmission circuit, station, or system is rated by the manufacturer.

Net Generation: Gross generation minus electricity used by the electricity generating plant (or company).

Nonutility: A corporation, person, agency, authority, or other legal entity or instrumentality that owns electric generating capacity and does not produce or sell electricity under a rate-regulation framework. Nonutility power producers include qualifying cogenerators, qualifying small power producers, and other nonutility generators (including independent power producers) without a designated franchised service area that do not file forms listed in the Code of Federal Regulations, Title 18, Part 141. (http://www.eia.doe.gov/emeu/iea/glossary.html)

Other Prime Movers: Methods of power generation other than steam turbines, combined cycles, gas combustion turbines, internal combustion engines, and hydroelectric generating units. Other prime movers include: geothermal, solar, wind, and biomass.

Peakload: A peakload generating unit, normally the least energy efficient of the three unit types, is used to meet requirements during the periods of greatest, or peak, load on the system. (http://www.eia.doe.gov/cneaf/electricity/page/prim2/chapter2.html)

Prime Movers: The engine, turbine, water wheel or similar machine that drives an electric generator. Also, for reporting purposes, a device that directly converts energy to electricity, e.g. photovoltaic, solar, and fuel cell(s).

Reliability: Electric system reliability has two components: adequacy and security. Adequacy is the ability of the electric system to supply customers at all times, taking into account scheduled and unscheduled outages of system plants. Security is the ability of the electric system to withstand sudden disturbances, such as electric short circuits or unanticipated loss of system plants. (http:/www.eia.doe.gov/cneaf/electricity/epav1/glossary.html)

Spinning Reserve: Reserve generating capacity running at a zero load and synchronized to the electric system. It is the unloaded section of synchronized generation that is able to respond immediately to serve load.

Steam Turbine: A generating unit in which the prime mover is a steam turbine. The turbines convert thermal energy (steam or hot water) produced by generators or boilers to mechanical energy or shaft torque. This mechanical energy is used to power electric generators, including combined cycle electric generating units that convert the mechanical energy to electricity.

System: Physically connected generation, transmission, and distribution plants operated as an integrated unit under one central management or operating supervision.

Transmission: The movement or transfer of electric energy over an interconnected group of lines and associated equipment between points of supply and points at which it is transformed for delivery to consumers, or is delivered to other electric systems. Transmission is considered to end when the energy is transformed for distribution to the consumer.

3 Compliance Costs

In developing the proposed ELGs, EPA assessed the costs and economic impacts of each of the eight regulatory options described in *Chapter 1: Introduction*. Key inputs for these analyses include the estimated costs to steam electric plants (and their business, government, or non-profit owners) for implementing control technologies to comply with the proposed ELGs, and to the State and federal governments 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 proposed ELGs are economically achievable, whether the compliance costs presents a barrier 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, 2013a; DCN SE01964). The *TDD* also describes how EPA estimated plant-specific capital and operating and maintenance (O&M) costs for complying with each of the eight regulatory options.

The following sections of this chapter summarize:

- The costs to existing steam electric plants for complying with these regulatory options (*Section 3.1*)
- The compliance costs to new steam electric power generating sources (*Section 3.2*)

EPA determined that State and federal governments would not incur incremental costs for administering the regulatory options and therefore did not develop cost estimates for this category.[35]

3.1 Costs to Existing Steam Electric Plants

EPA estimated costs to plants for complying with the requirements of the proposed ELG 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. Developing an estimated control technology implementation schedule based on the years when steam electric plants 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.

As described below, EPA used an analysis period that begins in 2014, the expected promulgation year, with all regulatory options analyzed as of that date. All costs are reported in 2010 dollars, based on the data available at the time EPA developed the analysis framework.

[35] As discussed in *Section 10.7: Paperwork Reduction Act of 1995*, EPA expects that the proposed ELG will not impose additional administrative cost to the State and federal governments.

3.1.1 Analysis Approach and Data Inputs

Plants Potentially Incurring Costs

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

As detailed in the *TDD*, EPA developed costs for steam electric plants to implement treatment technologies or process changes to control the wastestreams addressed by the proposed rule (e.g., bottom ash, fly ash, flue gas desulfurization (FGD), leachate, FGMC, gasification wastewater, and nonchemical metal cleaning wastes). Under the eight regulatory options, a plant may be subject to requirements 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).

The cost estimates reflect the incremental costs attributed only to the proposed ELGs, accounting for wastestreams and treatment systems already present in the baseline. For example, only plants that currently have FGD systems in the baseline are assumed to have the potential to generate this wastestream and may incur costs for treating their FGD wastewater under the proposed ELGs.[36] Further, plants with wastewater treatment systems that already meet the proposed limitations or standards would not incur costs to retrofit new technologies and therefore incur no cost under the regulatory options. In general, technology requirements and compliance costs assigned to each steam electric plant are based on the processes and technologies currently in place at the plant or anticipated to be implemented independent of ELG requirements by 2014, i.e., the year when the proposed ELGs are promulgated, based on information provided in the 2010 Questionnaire for the Steam Electric Power Generating Effluent Guidelines (industry survey; U.S. EPA, 2010a). Because steam electric plants are not expected to incur compliance technology costs for those wastestreams for which they already meet a given regulatory option‟s discharge requirements, some plants may incur compliance costs under only a subset of the eight regulatory options. Consequently, the number of plants estimated to incur compliance costs varies by regulatory option.

In identifying the plants that would incur costs under each of the regulatory options, EPA accounted for planned retirements and conversions identified in the industry survey and published sources (see *TDD*). For the analyses described in this report, EPA included all steam electric units expected to operate as of the ELG promulgation year of 2014. The analyses do not reflect additional planned unit retirements, repowerings, and conversions that have been announced since August 2012, nor do they reflect announced retirements, repowerings, and conversions that are scheduled to occur by 2022. The analyses therefore overstate total compliance costs by assigning costs to units and plants that would no longer operate by the time the proposed ELGs would need to be implemented (U.S. EPA, 2013d).

Plant-Level Costs

The *TDD* details the methodology EPA used to develop plant-level cost estimates for each wastestream and regulatory option.

EPA estimated compliance costs for the 676 steam electric plants that completed the industry survey (surveyed plants) and used sample weights to estimate total compliance costs for the remaining 403 plants, for

[36] EPA expects that some plants will upgrade their operations and treatment systems over the next few years, notably to comply with new air emission standards. These upgrades could have implications for this analysis by changing the characteristics of the wastestreams present at a plant. For example, a plant installing a new wet FGD system to comply with air emissions limits after 2014 might need to install or upgrade its wastewater treatment systems to treat the FGD-associated wastewater under the proposed ELG. To assess the effects of such changes to the characteristics of steam electric plants (i.e., denoted as the "future profile"), EPA conducted a sensitivity analysis for two of the BAT and PSES options (Options 3 and 4) that incorporates projected FGD installations in addition to FGD systems present in the baseline. The results of this analysis are presented in *Appendix B*.

a total universe of 1,079 steam electric plants. EPA estimates that only a subset of the 1,079 steam electric plants – up to 277 – may incur non-zero compliance costs, depending on their wastestreams and existing control technologies. Since all 277 plants are coal- or petroleum coal-fired and have a sample weight of 1, the sum of costs for the 277 plants also represents the total costs for the entire universe of 1,079 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 during their technology implementation year (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 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.
- *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 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.

EPA determined that the implementation of wastewater treatment systems for the proposed ELGs would not require any incremental 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 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 proposed ELGs. This profile is necessary to estimate the annualized costs to the steam electric industry and society.

EPA anticipates promulgating the revised ELGs in 2014.[37] As discussed in the preamble that accompanies the proposed rule, EPA envisions that each plant subject to the proposed ELGs would study available technologies and operational measures, and subsequently install, incorporate and optimize the technology most appropriate for each site. In evaluating technological availability and economic achievability, EPA considered the magnitude and complexity of process changes and new equipment installations that would be required at many existing facilities to meet the requirements of the rule. As discussed in the preamble that accompanies the proposed ELGs, EPA proposes that certain limitations and standards based on any of the five main regulatory options for existing direct and indirect dischargers do not apply until July 1, 2017 (approximately three years from the effective date of this rule). EPA find this is appropriate for any proposed BAT and PSES for FGD wastewater, gasification wastewater, fly ash transport water, flue gas mercury control wastewater, bottom ash transport water, or combustion residual leachate where EPA is not proposing to establish BAT limitations that are equal to BPT limitations. For those plants and wastestreams where EPA is proposing to establish BAT equal to the current BPT effluent limitations, the revised BAT requirements would be applicable on the effective date of the final rule. The proposed requirements for new direct and indirect dischargers (NSPS and PSNS) and the proposed requirements for existing sources where BAT is set equal to BPT would be applicable as of the effective date of the final rule.

EPA believes that this schedule provides a reasonable amount of time to raise capital, plan and design systems, procure equipment, and construct and then test systems. Moreover, this approach will enable facilities to take advantage of planned shutdown or maintenance periods to install new pollution control technologies.

For the cost and economic impact analyses, EPA assumed that plants would implement control technologies during the third year after renewal of their National Pollutant Discharge Elimination System (NPDES) permit, post-promulgation.[38] Assuming that NPDES permits are renewed every five years, steam electric plants are assumed to implement the control technologies within the 5-year window of calendar year 2017 through calendar year 2021. *Table 3-1* provides counts of steam electric plants that may potentially have to implement compliance technology and incur costs as the result of the proposed ELGs and their total generation capacity by estimated technology implementation year. As indicated earlier, EPA identified that up to 277 steam electric plants may incur non-zero compliance costs under one or more regulatory options, based on their wastestreams and existing control technologies.[39] As discussed earlier in this section, EPA expects that fewer plants may incur non-zero compliance costs when accounting for steam electric retirements, repowerings, and conversions that have been announced since August 2012 and for announced retirements, repowerings, and conversions that are scheduled to occur by 2022 (U.S. EPA, 2013d).

[37] EPA expects to finalize the proposed ELG in the spring of 2014. Because cost and economic impact analyses are conducted on a calendar-year basis, for the purpose of these analyses, EPA treated 2014 calendar year as the first post-promulgation analysis year.

[38] 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 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.

[39] There are 277 plants that generate and discharge FGD wastewater, fly ash transport water, bottom ash transport water, and/or combustion residual landfill leachate based on responses to the Questionnaire for the Steam Electric Power Generating Effluent Guidelines. As described in Section 9.2 of the *Technical Development Document*, EPA determined that there would be no costs associated with gasification wastewater, flue gas mercury control wastewater, and nonchemical metal cleaning wastes because the proposed ELG is either setting requirements that are already in place based on BPT or because the proposed BAT technology is already the current industry standard.

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

Technology	Plant Counts		Total Capacity	
Implementation Year[b]	**Counts**	**% of Total**	**Capacity (MW)**	**% of Total**
2017	54	19.5%	59,623	20.6%
2018	68	24.5%	67,800	23.4%
2019	56	20.2%	54,583	18.9%
2020	43	15.5%	50,105	17.3%
2021	56	20.2%	57,114	19.7%
Total	**277**	**100.0%**	**289,224**	**100.0%**

a. Of the 1,079 steam electric plants, only up to 277 plants may potentially incur non-zero compliance costs under any of the eight regulatory options.

Source: U.S. EPA Analysis, 2013

To assess the sensitivity of cost and economic impact analysis results to the technology implementation timeframe, EPA also analyzed two of the eight regulatory options (Options 3 and 4) assuming no delay after promulgation, i.e., plants would implement compliance technologies immediately upon renewal of their NPDES permits over the period of 2014 through 2018. The results of this sensitivity analysis are reported in *Appendix B*.

<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 obtained compliance costs for each of the 676 steam electric 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 2010 dollars, using the Construction Cost Index (CCI) from McGraw Hill Construction, the Employment Cost Index (ECI) published by the Bureau of Labor Statistics (BLS), and the Gross Domestic Product (GDP) deflator index published by the U.S. Bureau of Economic Analysis (BEA).[40]
- EPA discounted all cost values to the assumed year of rule promulgation, 2014, using a rate of 7 percent.[41]
- 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: [41]
  - Capital costs of each compliance technology: 20 years
  - Initial one-time costs: 20 years[42]

40 Specifically, EPA brought all compliance costs to an estimated technology implementation year using the Construction Cost Index (CCI) from McGraw Hill Construction or the Employment Cost Index (ECI) from the Bureau of Labor Statistics, 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 2010 dollars, the Agency deflated the nominal dollar values to 2010 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 2010.

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

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

- 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 1,079 steam electric 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 1,079 plants.

For the assessment of compliance costs to steam electric 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 pre-tax cost values for privately owned for-profit plants.[43] For this adjustment, EPA used State corporate rates from the Federation of Tax Administrators (http://www.taxadmin.org/) combined with federal corporate tax rate schedules from the Department of the Treasury, Internal Revenue Service. 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 11 of the BCA document, EPA uses pre-tax costs.

Projected Electricity Demand and Generation

With the exception of the market analyses discussed in Chapter 5,[44] 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 2014 as they did on average during 2007-2009.

3.1.2 Key Findings for Regulatory Options

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

As reported in *Table 3-2*, EPA estimates that, on a *pre-tax* basis, the 1,079 steam electric plants would incur annualized costs of complying with the proposed ELGs ranging from $168 million under Option 3a to $2,277 million under Option 5. On an *after-tax* basis, the costs range from $108 millionto $1,548 million.[45]

[43] 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 2006 EIA-860, and 2009 EIA-861 databases and additional research on parent entities using publically available information. See *Chapter 4: Economic Impact Screening Analyses* for further discussion of these determinations.

[44] In the Integrated Planning Model used for the electricity market analyses discussed in *Chapter 5*, demand growth assumptions are based on AEO 2010 where electricity demand is anticipated to grow by roughly 1 percent per year.

[45] These compliance costs do not reflect anticipated unit retirements and conversions announced between August 2012 and April 2013, and announced retirements, repowerings, and conversions that are scheduled to occur by 2022; EPA estimates that accounting for these changes would reduce total annualized compliance costs, and further, that the magnitude of this effect depends on the option analyzed. For example, EPA estimated that total pre-tax annualized compliance costs for *Option 3* would go from $561.3 million to $532.8 million (5 percent reduction) when including

The four preferred options – Options 3a, 3b, 3, and 4a – have respective total annualized after-tax compliance costs estimated at $108 million, $182 million, $389 million, and $636 million.

Table 3-2: Total Annualized Compliance Costs (in millions, $2010, at 2014)

	Pre-Tax Compliance Costs				After-Tax Compliance Costs			
Regulatory Option	Capital Technology	Other Initial One-Time[a]	Total O&M	Total	Capital Technology	Other Initial One-Time[a]	Total O&M	Total
3a	$28.0	$0.0	$140.1	$168.1	$18.6	$0.0	$89.8	$108.4
3b	$70.5	$0.0	$194.1	$264.6	$50.9	$0.0	$131.2	$182.2
1	$105.7	$0.0	$160.2	$265.9	$75.8	$0.0	$114.8	$190.6
2	$181.6	$0.0	$211.7	$393.3	$129.4	$0.0	$151.2	$280.6
3	$209.6	$0.0	$351.8	$561.3	$147.9	$0.0	$241.0	$389.0
4a	$389.8	$0.0	$557.9	$947.8	$263.8	$0.0	$371.9	$635.7
4	$568.5	$0.0	$804.7	$1,373.2	$382.2	$0.0	$534.6	$916.9
5	$838.9	$0.0	$1,438.3	$2,277.3	$572.5	$0.0	$975.3	$1,547.9

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, 2013

Table 3-3 reports costs at the level of a North American Electric Reliability Corporation (NERC) region. As explained in *Chapter 2: Industry Profile*, NERC is responsible for the overall reliability, planning, and coordination of the power grids; NERC is organized into regional organizations that are 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 of the NERC regions. Because of differences in operating characteristics of steam electric 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 proposed 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 region, followed by the FRC region, for all regulatory options, whereas two NERC regions, ASCC and HICC, have no costs for any of the eight options.

Table 3-3: Annualized Compliance Costs by NERC Region (in millions, $2010, at 2014)[a]

	Pre-Tax Compliance Costs				After-Tax Compliance Costs			
NERC Region[a]	Capital Technology	Other Initial One-Time[b]	Total O&M	Total	Capital Technology	Other Initial One-Time[b]	Total O&M	Total
Option 3a								
ASCC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
ERCOT	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
FRCC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
HICC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
MRO	$0.3	$0.0	$0.2	$0.5	$0.2	$0.0	$0.1	$0.3
NPCC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
RFC	$13.4	$0.0	$68.4	$81.8	$9.2	$0.0	$43.1	$52.3
SERC	$13.8	$0.0	$67.5	$81.3	$8.9	$0.0	$44.0	$52.9
SPP	$0.2	$0.0	$0.6	$0.8	$0.1	$0.0	$0.3	$0.5
WECC	$0.3	$0.0	$3.4	$3.7	$0.2	$0.0	$2.2	$2.4
Total	**$28.0**	**$0.0**	**$140.1**	**$168.1**	**$18.6**	**$0.0**	**$89.8**	**$108.4**
Option 3b								
ASCC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
ERCOT	$3.7	$0.0	$5.4	$9.1	$2.4	$0.0	$3.5	$5.9

announced unit retirements through 2024; whereas costs for Option 4 would go from $1,373.2 million to $1,252.9 million (9 percent reduction) (U.S. EPA, 2013d).

Table 3-3: Annualized Compliance Costs by NERC Region (in millions, $2010, at 2014)[a]

	Pre-Tax Compliance Costs				After-Tax Compliance Costs			
NERC Region[a]	Capital Technology	Other Initial One-Time[b]	Total O&M	Total	Capital Technology	Other Initial One-Time[b]	Total O&M	Total
FRCC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
HICC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
MRO	$0.3	$0.0	$0.2	$0.5	$0.2	$0.0	$0.1	$0.3
NPCC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
RFC	$25.2	$0.0	$81.9	$107.2	$16.4	$0.0	$51.3	$67.8
SERC	$39.7	$0.0	$102.1	$141.9	$31.0	$0.0	$73.4	$104.4
SPP	$1.2	$0.0	$1.1	$2.3	$0.8	$0.0	$0.7	$1.4
WECC	$0.3	$0.0	$3.4	$3.7	$0.2	$0.0	$2.2	$2.4
Total	**$70.5**	**$0.0**	**$194.1**	**$264.6**	**$50.9**	**$0.0**	**$131.2**	**$182.2**
Option 1								
ASCC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
ERCOT	$10.8	$0.0	$15.5	$26.3	$8.3	$0.0	$11.7	$20.0
FRCC	$1.6	$0.0	$1.4	$3.0	$1.1	$0.0	$0.8	$2.0
HICC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
MRO	$5.5	$0.0	$9.5	$15.0	$4.3	$0.0	$7.4	$11.7
NPCC	$0.6	$0.0	$0.7	$1.3	$0.4	$0.0	$0.4	$0.8
RFC	$30.4	$0.0	$43.9	$74.3	$18.7	$0.0	$26.6	$45.2
SERC	$51.7	$0.0	$83.6	$135.2	$39.9	$0.0	$64.2	$104.1
SPP	$4.5	$0.0	$5.2	$9.6	$2.8	$0.0	$3.3	$6.1
WECC	$0.7	$0.0	$0.5	$1.2	$0.4	$0.0	$0.3	$0.8
Total	**$105.7**	**$0.0**	**$160.2**	**$265.9**	**$75.8**	**$0.0**	**$114.8**	**$190.6**
Option 2								
ASCC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
ERCOT	$17.1	$0.0	$20.2	$37.3	$13.2	$0.0	$15.3	$28.5
FRCC	$6.3	$0.0	$4.9	$11.2	$4.6	$0.0	$3.5	$8.1
HICC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
MRO	$8.6	$0.0	$11.5	$20.1	$6.8	$0.0	$9.1	$15.9
NPCC	$1.6	$0.0	$1.4	$3.0	$1.0	$0.0	$0.8	$1.8
RFC	$59.2	$0.0	$62.2	$121.4	$36.7	$0.0	$38.1	$74.9
SERC	$79.9	$0.0	$102.9	$182.9	$61.5	$0.0	$79.0	$140.5
SPP	$7.7	$0.0	$7.5	$15.2	$4.8	$0.0	$4.7	$9.6
WECC	$1.2	$0.0	$1.0	$2.2	$0.7	$0.0	$0.6	$1.4
Total	**$181.6**	**$0.0**	**$211.7**	**$393.3**	**$129.4**	**$0.0**	**$151.2**	**$280.6**
Option 3								
ASCC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
ERCOT	$17.1	$0.0	$20.2	$37.3	$13.2	$0.0	$15.3	$28.5
FRCC	$6.3	$0.0	$4.9	$11.2	$4.6	$0.0	$3.5	$8.1
HICC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
MRO	$8.9	$0.0	$11.8	$20.7	$7.0	$0.0	$9.2	$16.2
NPCC	$1.6	$0.0	$1.4	$3.0	$1.0	$0.0	$0.8	$1.8
RFC	$72.5	$0.0	$130.7	$203.2	$45.9	$0.0	$81.2	$127.1
SERC	$93.7	$0.0	$170.4	$264.2	$70.4	$0.0	$123.1	$193.4
SPP	$7.9	$0.0	$8.1	$16.0	$5.0	$0.0	$5.1	$10.0
WECC	$1.4	$0.0	$4.4	$5.9	$0.9	$0.0	$2.8	$3.8
Total	**$209.6**	**$0.0**	**$351.8**	**$561.3**	**$147.9**	**$0.0**	**$241.0**	**$389.0**
Option 4a								
ASCC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
ERCOT	$26.0	$0.0	$30.0	$56.0	$19.2	$0.0	$21.9	$41.1
FRCC	$6.3	$0.0	$4.9	$11.2	$4.6	$0.0	$3.5	$8.1
HICC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
MRO	$15.1	$0.0	$18.1	$33.2	$11.0	$0.0	$13.4	$24.4
NPCC	$1.6	$0.0	$1.4	$3.0	$1.0	$0.0	$0.8	$1.8

Table 3-3: Annualized Compliance Costs by NERC Region (in millions, $2010, at 2014)[a]

	Pre-Tax Compliance Costs				After-Tax Compliance Costs			
NERC Region[a]	Capital Technology	Other Initial One-Time[b]	Total O&M	Total	Capital Technology	Other Initial One-Time[b]	Total O&M	Total
RFC	$153.0	$0.0	$225.1	$378.1	$95.3	$0.0	$139.0	$234.3
SERC	$160.0	$0.0	$247.4	$407.4	$114.8	$0.0	$173.4	$288.3
SPP	$21.2	$0.0	$20.8	$42.0	$13.7	$0.0	$13.4	$27.0
WECC	$6.6	$0.0	$10.3	$16.9	$4.1	$0.0	$6.5	$10.6
Total	$389.8	$0.0	$557.9	$947.8	$263.8	$0.0	$371.9	$635.7
Option 4								
ASCC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
ERCOT	$27.9	$0.0	$32.3	$60.2	$20.7	$0.0	$23.7	$44.4
FRCC	$8.7	$0.0	$7.9	$16.6	$6.9	$0.0	$6.5	$13.4
HICC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
MRO	$31.0	$0.0	$36.1	$67.1	$22.3	$0.0	$25.9	$48.2
NPCC	$10.2	$0.0	$8.7	$19.0	$6.2	$0.0	$5.3	$11.4
RFC	$228.8	$0.0	$331.2	$560.1	$142.5	$0.0	$204.6	$347.1
SERC	$215.3	$0.0	$334.1	$549.4	$152.7	$0.0	$232.8	$385.5
SPP	$30.9	$0.0	$30.6	$61.5	$20.9	$0.0	$20.6	$41.5
WECC	$15.7	$0.0	$23.6	$39.3	$10.1	$0.0	$15.3	$25.4
Total	**$568.5**	**$0.0**	**$804.7**	**$1,373.2**	**$382.2**	**$0.0**	**$534.6**	**$916.9**
Option 5								
ASCC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
ERCOT	$50.4	$0.0	$73.9	$124.3	$38.1	$0.0	$55.2	$93.3
FRCC	$24.2	$0.0	$48.0	$72.3	$18.5	$0.0	$34.4	$52.8
HICC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
MRO	$42.1	$0.0	$61.4	$103.4	$31.3	$0.0	$45.4	$76.7
NPCC	$14.6	$0.0	$11.7	$26.3	$8.8	$0.0	$7.0	$15.8
RFC	$323.4	$0.0	$590.0	$913.5	$202.3	$0.0	$366.1	$568.4
SERC	$324.1	$0.0	$578.5	$902.6	$234.1	$0.0	$418.5	$652.6
SPP	$41.5	$0.0	$49.7	$91.2	$27.5	$0.0	$32.6	$60.2
WECC	$18.6	$0.0	$25.1	$43.7	$11.9	$0.0	$16.2	$28.1
Total	**$838.9**	**$0.0**	**$1,438.3**	**$2,277.3**	**$572.5**	**$0.0**	**$975.3**	**$1,547.9**

a. The NERC regions used for the analysis of compliance costs to steam electric plants include: ASCC – Alaska Systems Coordinating Council; ERCOT – Electric Reliability Council of Texas; 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; and WECC – Western Energy Coordinating Council. No steam electric plant is expected to incur compliance costs in the ASCC and HICC NERC regions.
b. 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, 2013

3.1.3 Key Uncertainties and Limitations

This analysis is subject to 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 plants, based on plant-specific NPDES permit information.

3.2 Costs to New Sources

Electric power generating units that meet the definition of a "new source" would be required to achieve the proposed 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 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 preferred NSPS and PSNS option is based on the suite of technologies identified for Option 4. This section discusses the development and the impact of compliance costs on new units under Option 4 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 (*Section 3.1*). EPA is not able to predict which plants will construct new units, the exact characteristics of such units, or the timing of new unit construction. Instead, EPA calculated and analyzed compliance costs for a variety of 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., 2014.

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 *current* regulatory structure, and those that would likely be implemented because of the proposed ELGs.

Compliance costs for new units under Option 4 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. To develop total compliance costs for new units, EPA made the same adjustments as those made to develop total compliance costs for existing plants:

- First, EPA brought all compliance costs to the expected promulgation year of the proposed ELGs (2014) using CCI (or ECI), and restated in 2010 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-Yr O&M cost over 6 years, and 10-Yr 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 preferred new source option (Option 4). EPA considered coal steam units of different sizes (350 MW, 600 MW, and 1300 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 1300 MW unit would incur a total annualized compliance cost of about $5,013/MW when located at a new plant, and a cost of $4,037/MW when added to an existing plant. For more details on the methodology used to estimate compliance costs for new units, see the *TDD*.

Table 3-4: Annualized Pre-tax Compliance Costs for a New Unit Under Option 4 (Millions; at 2014; $2010)

New Unit and Plant Configuration	Capital Costs	Annual O&M	Annualized Compliance Costs	Unit Costs ($/MW) Capital Costs	Unit Costs ($/MW) O&M Costs	Unit Costs ($/MW) Annualized Compliance Costs
New Unit at New Plant						
350 MW	$14,226,981	$1,450,349	$2,705,420	$40,649	$4,144	$7,730
600 MW	$20,420,539	$2,108,619	$3,910,072	$34,034	$3,514	$6,517
1300 MW	$28,304,543	$4,020,459	$6,517,420	$21,773	$3,093	$5,013
New Unit at Existing Plant						
350 MW	$13,536,682	$1,120,404	$2,314,578	$38,676	$3,201	$6,613
600 MW	$16,239,067	$1,592,302	$3,024,874	$27,065	$2,654	$5,041

Table 3-4: Annualized Pre-tax Compliance Costs for a New Unit Under Option 4 (Millions; at 2014; $2010)

New Unit and Plant Configuration	Capital Costs	Annual O&M	Annualized Compliance Costs	Unit Costs ($/MW) Capital Costs	Unit Costs ($/MW) O&M Costs	Unit Costs ($/MW) Annualized Compliance Costs
1300 MW	$25,884,397	$2,964,838	$5,248,299	$19,911	$2,281	$4,037

Source: U.S. EPA Analysis, 2013

3.2.2 Key Findings for Regulatory Options

EPA assessed the effects of proposed ELG requirements for new units in two ways:

- First, 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*.
- Second, by incorporating these costs as part of its electricity market analyses using the Integrated Planning Model (IPM) discussed in *Chapter 5: Electricity Market Analyses*. 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 complying with the proposed ELGs would affect future capacity additions.

The rest of this section discusses the first analysis. See *Chapter 5* for discussion of the electricity market analyses.

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 2011 (AEO2011) 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, 2011a).[46] EPA annualized new dual-unit plant building and operating costs over 20 years using a rate of 7 percent.[47] EPA then compared the 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 0.4 percent of the cost of a new plant, while compliance costs for adding a new unit at an existing plant represent 1.2 percent of the cost of building a new plant.

[46] 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.

[47] 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 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.

Table 3-5: Capital and O&M Costs for New 1,300 MW Coal-Fired Steam Electric Plant per MW of Capacity (Millions; at 2014; $2010)

Cost Component	Costs of New Coal-fired Generation ($2010/MW)[a]	Unit Configuration	Incremental Compliance Costs ($2010/MW)[b]	% of New Generation Cost
Capital	$2,981,947	Based on new plant	$21,773	0.7%
		Based on existing plant	$19,911	0.7%
Annual O&M	$66,427	Based on new plant	$3,093	4.7%
		Based on existing plant	$2,281	3.4%
Total annualized costs	$329,487	Based on new plant	$5,013	1.5%
		Based on existing plant	$4,037	1.2%

a. New unit total cost value from Table 8.2 EIA NEMS Electricity Market Module. AEO2011 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 2014. EPA restated cost in 2010 dollars, as of 2014. Total annual O&M costs assume 90 percent capacity utilization.
b. Incremental costs for new 1,300 MW unit for Option 4. Range represents the costs for a new unit at a newly constructed plant (upper bound) and new unit at an existing plant (lower bound).
Sources: U.S. DOE, 2011a; U. S. EPA Analysis, 2013.

3.2.3 Key Uncertainties and Limitations

This analysis is subject to uncertainties and limitations. In particular, 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-estimated.

4 Cost and Economic Impact Screening Analyses

4.1 Analysis Overview

EPA assessed the costs and economic impacts of the eight 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 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 requirements of the proposed ELGs. 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 plants (*Section 4.2*)
   - A cost-to-revenue screening analysis to assess the impact of compliance outlays on domestic parent-entities owning steam electric 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 proposed ELGs, including an assessment of plant closures, is discussed in *Chapter 5: Electricity Market Analyses*. 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 of the regulatory options. As discussed in *Chapter 2: Industry Profile*, the majority of steam electric 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.[48]

In assessing the cost impact of the eight regulatory options on complying plants in this screening-level analysis, the Agency assumed that steam electric plants would not be able to pass any of the increase in their

[48] 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.

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 plants. Even though the majority of steam electric 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 proposed ELGs to steam electric plants and their parent entities. To the extent that some steam electric plants are able to recover some of the increased production costs in increased prices, this analysis overstates plant-level impacts.[49] 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 plants to meet the effluent limits and standards set in the proposed ELGs by 2022, with economic impact analyses generally conducted assuming a 5-year window of 2017 through 2021 during which plants would implement compliance technologies and would meet the revised effluent limits and standards.[50]

In comparing compliance costs to revenue at the plant level, EPA used a single year of 2014 as the basis for the analysis. Specifically, EPA compared annualized after-tax compliance costs[51] (see *Chapter 3*) with estimated plant revenue in 2014.[52]

EPA developed plant-level revenue values for all steam electric 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 3-year average of electricity generation values over the period 2007 to 2009 from the EIA-906/920/923 database by 3-year average electricity prices over the period 2007 to 2009 from the EIA-861 database (U.S. DOE, 2009b; U.S. DOE, 2009c).[53] For this analysis, EPA assumed that a plant would generate approximately the same quantity of electricity in 2014 as it did on average during 2007 through 2009.

To provide cost and revenue comparisons on a consistent analysis-year (2014) and dollar-year (2010) basis, EPA made the following adjustments:

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[49] To evaluate the sensitivity of the results to the cost pass-through assumption, EPA also analyzed two of the eight options (Options 3 and 4) assuming that steam electric plants will be able to pass through a fraction of their compliance costs to consumers through higher electricity rates (Fifty-Percent Cost-Pass-Through). EPA used 50 percent as an illustrative cost-pass through assumption. The results of this sensitivity analysis are reported in *Appendix B*.

[50] To evaluate the sensitivity of the results to the compliance window assumption, EPA also analyzed two of the eight options (Options 3 and 4) assuming that all steam electric plants will implement the control technologies immediately upon renewal of their NPDES permit during the first five years after promulgation (2014 through 2018). The results of this sensitivity analysis are reported in *Appendix B*.

[51] 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.

[52] Although steam electric plants are expected to implement control technologies during a window of time that is farther into the future, 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 2014 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 2014, cost and revenue values are assumed to change at the same rate and thus the ratio of these values will be constant over time.

[53] In using the year-by-year revenue 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 likely results from temporary disruption in operation, such as a generating unit being out of service for maintenance.

- 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 2010 dollars using the Gross Domestic Product (GDP) deflator index published by the U.S. Bureau of Economic Analysis (BEA). These individual yearly values were then averaged and brought forward to 2014 using electricity price projections from the Annual Energy Outlook publication for 2011 (*AEO2011*) (U.S. DOE, 2011a).[54,55,56]
- Compliance cost values were originally estimated as of 2010. To bring all compliance costs, except the initial planning costs, to 2014, EPA used the average of the year-to-year changes in the McGraw Hill Construction‟s 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, 2014, and in 2014 dollars. To re-state compliance cost values in 2010 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 2014, EPA used the average of the year-to-year changes in the Employment Cost Index (ECI) from the Bureau of Labor Statistics (BLS) over the most recent ten-year reporting period. EPA used a different index for this cost component to account for the composition of this one-time cost, which 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 2014 and in 2014 dollars. To re-state these cost values in 2010 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. EPA applied sample weights (see *Technical Development Document (TDD)* (U.S. EPA, 2013a; DCN SE01964) for a discussion on weights development) to the individual surveyed plants within each impact category to estimate the number of plants at the population-level incurring these cost burdens.

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 plants, including those expected to incur zero compliance costs, costs would not exceed the 1 percent of revenue threshold under any of the eight regulatory options. Thus, for the four preferred options, 92 percent to 97 percent of plants have costs less than 1 percent of revenue. This finding generally applies to plants of all ownership types.

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[54] AEO is published by the Energy Information Administration (EIA). *AEO2011* contains projections and analysis of U.S. energy supply, demand, and prices through 2035; these projections are based on the EIA‟s National Energy Modeling System (NEMS).

[55] *AEO2012* data were released after EPA completed these analyses. If *AEO2012* electricity price projections were used, plant revenue values would have been approximately 5 percent higher.

[56] *AEO2010* electricity price projections are in constant dollars; therefore, these adjustments yield 2014 revenue values in dollars of the year 2010.

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

Owner Type	Total Number of Plants	No Revenue[b]	Number of Plants with a Ratio of			
			0%[c]	≠0 and <1%	≥1 and <3%	≥3%
Option 3a						
Cooperative	67	1	62	3	1	0
Federal	15	0	15	0	0	0
Investor-owned	680	3	620	37	19	1
Municipality	122	0	120	1	1	0
Nonutility	150	1	149	0	0	0
Other Political Subdivision	41	0	41	0	0	0
State	5	0	2	2	1	0
Total	**1,079**	**5**	**1,008**	**43**	**22**	**1**
Option 3b						
Cooperative	67	1	62	3	1	0
Federal	15	0	13	0	1	1
Investor-owned	680	3	610	46	20	1
Municipality	122	0	120	1	1	0
Nonutility	150	1	148	1	0	0
Other Political Subdivision	41	0	41	0	0	0
State	5	0	1	3	1	0
Total	**1,079**	**5**	**994**	**54**	**24**	**2**
Option 1						
Cooperative	67	1	56	5	3	2
Federal	15	0	10	1	4	0
Investor-owned	680	3	596	73	6	2
Municipality	122	0	113	7	1	1
Nonutility	150	1	142	5	2	0
Other Political Subdivision	41	0	40	1	0	0
State	5	0	3	1	1	0
Total	**1,079**	**5**	**959**	**93**	**17**	**5**
Option 2						
Cooperative	67	1	56	4	3	3
Federal	15	0	10	1	3	1
Investor-owned	680	3	596	71	6	4
Municipality	122	0	113	4	2	3
Nonutility	150	1	142	4	3	0
Other Political Subdivision	41	0	40	1	0	0
State	5	0	3	1	1	0
Total	**1,079**	**5**	**959**	**86**	**18**	**11**
Option 3						
Cooperative	67	1	54	5	4	3
Federal	15	0	10	1	3	1
Investor-owned	680	3	561	84	27	5
Municipality	122	0	113	4	1	4
Nonutility	150	1	142	4	3	0
Other Political Subdivision	41	0	40	1	0	0
State	5	0	1	3	0	1
Total	**1,079**	**5**	**920**	**102**	**38**	**14**
Option 4a						
Cooperative	67	1	51	4	7	4
Federal	15	0	10	1	3	1
Investor-owned	680	3	521	98	48	10
Municipality	122	0	112	3	3	4
Nonutility	150	1	141	5	3	0
Other Political Subdivision	41	0	40	1	0	0
State	5	0	1	2	1	1
Total	**1,079**	**5**	**875**	**114**	**65**	**20**

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

Owner Type	Total Number of Plants	No Revenue[b]	Number of Plants with a Ratio of			
			0%[c]	≠0 and <1%	≥1 and <3%	≥3%
Option 4						
Cooperative	67	1	47	2	9	8
Federal	15	0	9	2	3	1
Investor-owned	680	3	469	90	93	25
Municipality	122	0	99	6	7	10
Nonutility	150	1	137	8	3	1
Other Political Subdivision	41	0	37	3	0	1
State	5	0	1	0	2	2
Total	**1,079**	**5**	**798**	**111**	**117**	**48**
Option 5						
Cooperative	67	1	47	2	7	10
Federal	15	0	9	2	0	4
Investor-owned	680	3	469	73	95	40
Municipality	122	0	99	4	7	12
Nonutility	150	1	137	6	3	3
Other Political Subdivision	41	0	37	2	1	1
State	5	0	1	0	2	2
Total	**1,079**	**5**	**798**	**89**	**115**	**72**

a. Plant counts are weighted estimates.
b. EIA reports no revenue for 3 plants (5 on a weighted basis); only 1 of these 5 plants is expected to incur compliance cost under any of the eight regulatory options.
c. 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, 2013

4.2.3 Uncertainties and Limitations

The analysis of plant-level impacts is subject to uncertainties and limitations, including:

- To the extent that actual 2014 plant revenue values differ from those estimated using EIA databases for 2007, 2008, and 2009, the impact of the proposed 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 plants are able to pass at least some compliance costs to consumers through higher electricity prices, this analysis overstates the potential impact of the proposed ELGs on steam electric plants.
- The compliance costs used in this analysis do not reflect anticipated unit retirements and conversions announced between August 2012 and April 2013, and announced retirements, repowerings, and conversions that are scheduled to occur by 2022. As discussed in *Chapter 3*, accounting for these changes would reduce total annualized compliance costs.

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 complying 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 plant.[57,58] As it 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.[59]

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

Therefore, for the entity-level analysis, EPA considered 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 plant. This entity-level cost-to-revenue analysis involved the following steps:

- 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 plant (676 plants) (for a discussion of the industry survey and the use of sample weights, see *TDD*).[60] To determine ownership, EPA relied primarily on the information from the industry survey. For plants for which the industry survey

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57 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.

58 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.

59 To evaluate the sensitivity of the results to the zero cost pass-through assumption, EPA also analyzed Option 3 assuming that steam electric plants, and consequently their parent entities, will be able to pass through some of their compliance costs to consumers through higher electricity prices. EPA used 50 percent as an illustrative cost-pass through assumption. The results of this sensitivity analysis are reported in *Appendix B*.

60 EPA estimated costs for surveyed plants (i.e., 676 plants). The remaining 403 plants are accounted for through application of sample weights to the surveyed plants, for a total universe of 1,079 plants.

did not provide this information, the Agency used the 2009 EIA-861 and 2009 EIA-860 databases and corporate/financial websites (U.S. DOE, 2009a; U.S. DOE, 2009b).

Using the same sources, EPA determined each parent entity‟s shares of ownership in the surveyed steam electric 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 publicly owned entities 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 owned entities 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 2010 dollars using the GDP Deflator. For this analysis, the Agency assumed that these average revenue values were as of 2014. Although the entity-level revenue values might reasonably be expected to change by 2014, EPA was less confident in the reliability of projecting revenue values *at the entity level* than in that of projecting plant-level revenue values (*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, complying plants and their parent entities are assumed to be the same „business entities‟ in terms of constant dollar revenue in 2014 as they were at the time of the industry survey.

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 plants. To account for the parent entities of all 1,079 steam electric plants, EPA therefore considered 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 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 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 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 plant, and the analysis is straightforward: the entity owns one steam electric 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. EPA found that 3 entities own more than one surveyed plant. 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.

In all 3 instances, however, the surveyed plants that are owned by the same entity have 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 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 eight regulatory options; for the four preferred options, 87 percent (under Option 4a) to 93 percent (under Option 3a) of entities have annualized costs less than 1 percent of revenue.[61] This observation holds under Case 2 which shows the same number of entities with cost-to-revenue ratios greater than zero; for the four preferred options, the fraction of entities with costs less than 1 percent of revenue ranges from 91 percent (under Option 4a) to 94 percent (under Option 3a).

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.

[61] 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 plants						Case 2: Upper bound estimate of number of entities owning steam electric 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 3a												
Cooperative	30	25	3	1	0	1	52	45	3	1	0	3
Federal	2	1	0	0	0	1	4	3	0	0	0	1
Investor-owned	97	77	17	0	0	3	244	217	17	0	0	10
Municipality	65	63	1	1	0	0	101	99	1	1	0	0
Nonutility	35	27	0	0	0	8	73	61	0	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**	**205**	**22**	**2**	**0**	**14**	**507**	**453**	**22**	**2**	**0**	**30**
Option 3b												
Cooperative	30	25	3	1	0	1	52	45	3	1	0	3
Federal	2	0	1	0	0	1	4	2	1	0	0	1
Investor-owned	97	75	19	0	0	3	244	215	19	0	0	10
Municipality	65	63	1	1	0	0	101	99	1	1	0	0
Nonutility	35	26	1	0	0	8	73	60	1	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**	**201**	**26**	**2**	**0**	**14**	**507**	**449**	**26**	**2**	**0**	**30**
Option 1												
Cooperative	30	19	8	0	2	1	52	39	8	0	2	3
Federal	2	0	1	0	0	1	4	2	1	0	0	1
Investor-owned	97	63	30	0	1	3	244	203	30	0	1	10
Municipality	65	56	7	1	1	0	101	92	7	1	1	0
Nonutility	35	24	3	0	0	8	73	58	3	0	0	13
Other Political Subdivision	12	10	1	0	0	1	30	26	1	0	0	3
State	2	1	1	0	0	0	2	1	1	0	0	0
Total	**243**	**173**	**51**	**1**	**4**	**14**	**507**	**421**	**51**	**1**	**4**	**30**
Option 2												
Cooperative	30	19	7	1	2	1	52	39	7	1	2	3
Federal	2	0	1	0	0	1	4	2	1	0	0	1
Investor-owned	97	63	30	0	1	3	244	203	30	0	1	10
Municipality	65	56	4	4	1	0	101	92	4	4	1	0
Nonutility	35	24	2	1	0	8	73	58	2	1	0	13
Other Political Subdivision	12	10	1	0	0	1	30	26	1	0	0	3
State	2	1	1	0	0	0	2	1	1	0	0	0
Total	**243**	**173**	**46**	**6**	**4**	**14**	**507**	**421**	**46**	**6**	**4**	**30**
Option 3												
Cooperative	30	18	7	2	2	1	52	38	7	2	2	3
Federal	2	0	1	0	0	1	4	2	1	0	0	1
Investor-owned	97	59	34	0	1	3	244	199	34	0	1	10
Municipality	65	56	4	3	2	0	101	92	4	3	2	0
Nonutility	35	24	2	1	0	8	73	58	2	1	0	13
Other Political Subdivision	12	10	1	0	0	1	30	26	1	0	0	3
State	2	1	0	1	0	0	2	1	0	1	0	0
Total	**243**	**168**	**49**	**7**	**5**	**14**	**507**	**416**	**49**	**7**	**5**	**30**
Option 4a												
Cooperative	30	15	9	3	2	1	52	35	9	3	2	3
Federal	2	0	1	0	0	1	4	2	1	0	0	1
Investor-owned	97	54	37	2	1	3	244	194	37	2	1	10

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

Entity Type	Case 1: Lower bound estimate of number of entities owning steam electric plants						Case 2: Upper bound estimate of number of entities owning steam electric 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]
Municipality	65	55	3	4	3	0	101	91	3	4	3	0
Nonutility	35	22	4	1	0	8	73	56	4	1	0	13
Other Political Subdivision	12	10	1	0	0	1	30	26	1	0	0	3
State	2	1	0	1	0	0	2	1	0	1	0	0
Total	**243**	**157**	**55**	**11**	**6**	**14**	**507**	**405**	**55**	**11**	**6**	**30**
Option 4												
Cooperative	30	13	9	5	2	1	52	33	9	5	2	3
Federal	2	0	1	0	0	1	4	2	1	0	0	1
Investor-owned	97	50	39	4	1	3	244	190	39	4	1	10
Municipality	65	45	7	9	4	0	101	81	7	9	4	0
Nonutility	35	20	5	2	0	8	73	54	5	2	0	13
Other Political Subdivision	12	8	3	0	0	1	30	24	3	0	0	3
State	2	1	0	1	0	0	2	1	0	1	0	0
Total	**243**	**137**	**64**	**21**	**7**	**14**	**507**	**385**	**64**	**21**	**7**	**30**
Option 5												
Cooperative	30	13	20	7	4	1	52	33	7	5	4	3
Federal	2	0	0	0	0	1	4	2	0	1	0	1
Investor-owned	97	50	85	35	3	3	244	190	35	6	3	10
Municipality	65	45	52	7	6	0	101	81	7	7	6	0
Nonutility	35	20	25	5	1	8	73	54	5	1	1	13
Other Political Subdivision	12	8	11	3	0	1	30	24	3	0	0	3
State	2	1	1	0	1	0	2	1	0	0	1	0
Total	**243**	**137**	**57**	**20**	**15**	**14**	**507**	**385**	**57**	**20**	**15**	**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, 2013

4.3.3 Uncertainties and Limitations

The analysis of entity-level impacts is subject to 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 2014 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 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 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 proposed ELGs.

- The compliance costs used in this analysis do not reflect anticipated unit retirements and conversions announced between August 2012 and April 2013, and announced retirements, repowerings, and conversions that are scheduled to occur by 2022. As discussed in *Chapter 3*, EPA estimates that accounting for these changes would reduce total annualized compliance costs.

5 Assessing the Impact of the Proposed 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 has 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 proposed ELG options, EPA used an updated version of this same analytic system: Integrated Planning Model Version 4.10 MATS (IPM V4.10) (U.S. EPA, 2010c), summarized in *Appendix C: Overview of the Integrated Planning Model*.[62]

The market model analysis is a more comprehensive analysis compared to the screening-level analyses discussed in *Chapter 4: Economic Impact Screening Analyses*; it is meant to inform EPA‟s assessment of the economic achievability of the proposed ELGs under CWA Section 304(b)(2) and determine whether the proposed ELGs would result in any capacity retirements (full or partial plant closures). 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 3 and then Option 4, with the notion to proceed if additional model runs were warranted.

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 proposed 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 2010* (AEO 2010), whereas the screening-level analyses discussed in other chapters of this report assume that plants would generate approximately the same quantity of electricity in 2014 as they did on average during 2007-2009.

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

EPA‟s use of IPM V4.10 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 C*, 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.

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

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.

In analyzing the proposed ELGs, EPA specified additional fixed and variable costs that are expected to be incurred by steam electric plants and generating units to comply with effluent limits and standards and 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 proposed ELGs and the key outputs reviewed as indicators of the effect of the regulatory options.
- *Section 5.2* describes the regulatory options considered in the market model analysis and how these options map to the broader set of regulatory options that EPA considered for the proposed ELGs.
- *Section 5.3* provides the findings from the market model analysis.
- *Section 5.4* identifies key uncertainties and limitations in the market model analysis.

5.1 Model Analysis Inputs and Outputs

To assess the impact of the proposed ELGs, EPA compared each of two policy runs (post-compliance cases corresponding to Option 3 and Option 4) to the IPM V4.10 baseline projection of electricity markets and plant operations.

5.1.1 Analysis Years

As discussed in *Appendix C*, IPM V4.10 models the electric power market over the 43-year period from 2012 to 2054. Within this total analysis period, EPA looked at shorter IPM analysis periods (run-year windows)[63] to assess the market-level effect of the proposed ELGs. To assess the impact of the proposed ELGs during the period in which steam electric plants are implementing the control technologies (the technology implementation period) – the *short-term* effects analysis – EPA used results reported for the 2020 IPM run year. As discussed in *Chapter 3: Compliance Costs*, steam electric plants are expected to implement control technologies to meet the proposed ELG requirements during a 5-year window of 2017 through 2021. Because this technology implementation window falls within the time period captured by the 2020 run year (i.e., 2017-2024), EPA judges that 2020 is an appropriate year to capture regulatory effects during the transition. Because of the potential increase in electricity production costs at steam electric 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 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 plants that incur relatively lower compliance

[63] 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.

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 proposed ELGs on electricity markets during the period *after* technology implementation by *all* steam electric plants – the *steady state* post-compliance period – EPA analyzed results reported for the IPM 2030 run year.[64] 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., 2021, and continue into the future. The 2021 analysis year is captured in the IPM 2020 run year, as opposed to the 2030 run year. However, because all analysis years represented by the 2030 run year (i.e., 2025-2034) fall outside the technology implementation window of 2017 through 2021, EPA judges that 2030 is an appropriate 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 plants, and, as described above, the need to dispatch other, potentially higher production cost, generating units to offset losses in electric generating capacity.

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.4.10.

5.1.2 Key Inputs to IPM V4.10 for the Proposed ELGs Market Model Analysis

Existing Plants

The inputs for the electricity market analyses include compliance costs and the technology implementation year. IPM models 665 of the 676 surveyed steam electric plants.[65,66] EPA developed compliance cost input values for 292 surveyed plants,[67] based on the costing methodologies described in the *TDD*; 290 of these 292 plants are modeled in IPM (U.S. EPA, 2013a; DCN SE01964). The other 375 of the 665 surveyed plants present in the IPM universe do not incur compliance costs under the two regulatory options EPA analyzed using IPM.

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.

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64 The 2020 run year accounts for costs recognized within the period of 2017-2024. 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.

65 EPA estimated compliance costs for the 676 steam electric plants that completed the industry survey (surveyed plants) and used sample weights to estimate total compliance costs for the remaining 403 plants, for a total universe of 1,079 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.

66 Eleven 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 3 plants excluded from the IPM baseline as the result of custom adjustments made by ICF based on the proprietary information about existing power-plant universe.

67 These 292 surveyed plants represent a total of 294 plants, after applying the sample weights.

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 plants are expected to incur these costs only once.[68] 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-type 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 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. As discussed in *Chapter 3*, EPA assumed that each steam electric plant would meet the revised effluent limits and standards three years after its first post-promulgation NPDES permit renewal, resulting in control technologies being implemented at steam electric plants during the period of 2017 through 2021.[69]

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68 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.

69 EPA obtained information on NPDES permit renewals from either the steam electric industry survey, the Water Permit Compliance System (PCS), or the Integrated Compliance Information Systems – National Pollutant Discharge Elimination System (ICIS-NPDES).

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.[70]

New Capacity

Steam electric generating units that meet the definition of a "new unit" would be required to meet the proposed New Source Performance Standards (NSPS) and Pretreatment Standards for New Sources (PSNS). As discussed in *Chapter 3*, the proposed ELGs establish NSPS and PSNS based on the suite of technologies identified in Option 4. For new units, the Option 4 technology basis is used in IPM analyses of both "Option 3" and Option 4 discussed in this Chapter.[71]

For the new capacity analysis, EPA analyzed the cost impact of proposed standards for new coal-fired units. Compliance costs for these new units under Option 4 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.[72] For the Market Model Analysis, EPA annualized capital costs over the entire Market Model Analysis period of 43 years (see *Appendix C*).[73] See *TDD* for a detailed discussion on estimation of new capacity and associated compliance costs.

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

IPM V4.10 provides outputs for the NERC regions that lie within the continental United States. As described above, IPM V4.10 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 V4.10 generates a series of outputs at different levels of aggregation (model plant, region, and nation). The economic analysis for the proposed ELGs used a subset of the available IPM output. For each model run

70 IPM seeks to minimize the total, discounted net present value, of the costs of meeting demand, accounting for power operation constraints, and environmental regulations over the entire planning horizon. These costs include the cost of any new plant, pollution control construction, fixed and variable operating and maintenance costs, and fuel costs. As described in the IPM documentation, "*capital costs in IPM's objective function are represented as the net present value of levelized stream of annual capital outlays, not as a one-time total investment cost. The payment period used in calculating the levelized annual outlays never extends beyond the model's planning horizon: it is either the book life of the investment or the years remaining in the planning horizon, whichever is shorter. This 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)

71 Note that the NSPS and PSNS compliance costs analyzed in IPM for "Option 3" scenario differ slightly from those analyzed for the "Option 4" scenario, because they do not include some compliance technology cost elements that were determined only after IPM analysis of Option 3 had been completed.

72 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*.

73 As described in *Chapter 3*, EPA assumed 20 years as the operating life of a new coal unit, based on information from the Annual Energy Outlook published by the U.S. Department of Energy‟s (DOE) Energy Information Administration (EIA). However, the 43-year assumption was necessary to incorporate capital costs into IPM analysis.

(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.
- *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 proposed 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 complying with the proposed ELGs.
- *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 proposed 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 proposed ELG options on steam electric plants and the broader electric power markets.[74]

5.2 Regulatory Options Analyzed

Due to scheduling constraints associated with running IPM, EPA selected two of the eight 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 3 and Market Model Analysis Option 4 (for description of the regulatory options see *Chapter 1: Introduction*). These Market Model Analysis Options align *approximately* with regulatory Options 3 and 4, respectively, described in *Chapter 1* and discussed

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

elsewhere in this report. To avoid disclosing confidential business information (CBI) reported in the industry survey and used to develop compliance costs, EPA had to use slightly different compliance cost estimates for some plants under both options analyzed in IPM. Additionally, the Market Model Analysis Option 3 analyzed in IPM is different from the proposed Option 3 discussed elsewhere in this report in the following ways:

- The Market Model Analysis Option 3 does not include some compliance technology cost elements that were determined only after IPM analysis of Option 3 had been completed.[75]
- For the Market Model Analysis Option 3, EPA assumed that steam electric plants would start to incur savings from not needing to periodically maintain ash/FGD pond systems starting in the technology implementation year, as opposed to 5 years later.
- The Market Model Analysis Option 3 does not include changes made to the universe of steam electric plants assigned compliance costs based on additional data review conducted and changes to the rule specifications made after IPM analysis of Option 3 had been completed.[76]

EPA estimates that because of these changes made later in the rule development process and adjustments to the cost estimates to avoid CBI disclosure, overall, Market Model Analysis Option 3 costs are approximately 10 percent lower than costs of the proposed Option 3 discussed in other chapters of this document.[77] EPA estimates that because of the adjustments made to cost estimates to avoid CBI disclosure, Market Model Analysis Option 4 costs are approximately 1 percent lower than costs of the regulatory Option 4. As mentioned in Section 5.1.2, both Market Model Analysis scenarios assign costs for new sources based on the preferred NSPS and PSNS technology basis (Option 4).

The two scenarios analyzed in IPM – Option 3 and Option 4 – provide insight on the market impacts of the regulatory options EPA considered for this action. Options 3 and 4 provide valuable insight on the likely impacts of the proposed options. The impacts of Option 4a are expected to be between those of Options 3 and 4. Options 3a, 1, 2 and 3b are less stringent than either of the two other options analyzed in IPM; as discussed below, the relatively small impacts observed when using Option 3 suggest that impacts of Options 3a, 1, 2 and 3b would be similarly small. EPA did not analyze Option 5 based on screening-level analysis results discussed in *Chapter 4: Economic Impact Screening Analyses*, which showed that compliance costs could result in financial stress to some entities owning steam electric plants. As discussed in *Section 4.3*, about three times and twice as many entities owning steam electric plants would incur costs, under Option 5, of at least 3 percent of revenue than under Options 3 and 4, respectively. Thus, going from Option 3 to Option 4 results in 2 more entities estimated to have costs greater than 3 percent of revenue (5 vs. 7 entities), whereas going from Option 4 to Option 5 results in an additional 8 entities with costs greater than 3 percent of revenue (7 vs. 15 entities).

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-regulation 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 proposed ELGs, EPA compared baseline and policy IPM results reported for 2030. These results

[75] These costs are the 6-year mercury analyzer O&M costs, costs for pump/feedback system for FGD treatment, and BMP costs for pond inspections.

[76] Specifically, 11 steam electric plants assigned compliance costs under the proposed Option 3 are not assigned compliance costs under the Market Model Analysis Option 3 and 18 steam electric plants assigned costs in the Market Model Analysis Option 3 are not assigned compliance costs under the proposed Option 3.

[77] This calculation was made using annualized costs estimated using the methodology outlined in *Chapter 3*.

provide insight on the effect of the proposed 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 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 2025 through 2035, 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 plants as a group, and
- Impact on individual steam electric 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 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 proposed 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 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 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 proposed 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.

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

Economic Measures	Baseline	Option 3			Option 4		
(all dollar values in $2010)	Value	Value	Difference	% Change	Value	Difference	% Change
National Totals							
Total Capacity (GW)	1,106	1,106	1	0.0%	1,106	0	0.0%
Existing			0	0.0%		0	0.0%
New Additions			0	0.0%		0	0.0%
Early Retirements			0	0.0%		0	0.0%
Electricity Prices ($/MWh)	NA	NA	NA	NA	NA	NA	NA
Generation (TWh)	4,701	4,701	0	0.0%	4,701	0	0.0%
Costs ($Millions)	$218,113	$218,986	$872	0.4%	$219,987	$1,874	0.9%
Fuel Cost	$117,471	$117,628	$157	0.1%	$117,464	-$7	0.0%
Variable O&M	$15,913	$16,266	$352	2.2%	$16,755	$841	5.3%
Fixed O&M	$58,781	$59,141	$360	0.6%	$59,806	$1,026	1.7%
Capital Cost	$25,948	$25,951	$3	0.0%	$25,962	$14	0.1%
Variable Production Cost ($/MWh)	$28.37	$28.48	$0.11	0.4%	$28.55	$0.18	0.6%
CO_2 Emissions (Million Metric Tons)	2,451	2,449	-1	-0.1%	2,446	-4	-0.2%
Hg Emissions (Tons)	9	9	0	-0.1%	9	0	-0.4%
NOx Emissions (Million Tons)	2	2	0	0.1%	2	0	0.1%
SO_2 Emissions (Million Tons)	2	2	0	-0.1%	2	0	-0.2%
HCL Emissions (Million Tons)	0	0	0	0.1%	0	0	0.1%
Electric Reliability Council of Texas (ERCOT)							
Total Capacity (GW)	98	98	0	0.0%	98	0	-0.1%
Existing			0	0.0%		0	0.0%
New Additions			0	0.0%		0	-0.1%
Early Retirements			0	0.0%		0	0.0%
Electricity Prices ($/MWh)	$66.20	$66.40	$0.21	0.3%	$66.27	$0.07	0.1%
Generation (TWh)	393	393	0	0.0%	393	0	0.0%
Costs ($Millions)	$18,014	$18,086	$72	0.4%	$18,099	$85	0.5%
Fuel Cost	$11,737	$11,762	$25	0.2%	$11,761	$24	0.2%

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

Economic Measures (all dollar values in $2010)	Baseline Value	Option 3 Value	Option 3 Difference	Option 3 % Change	Option 4 Value	Option 4 Difference	Option 4 % Change
Variable O&M	$1,403	$1,419	$17	1.2%	$1,437	$34	2.5%
Fixed O&M	$3,777	$3,801	$24	0.6%	$3,821	$44	1.2%
Capital Cost	$1,097	$1,103	$6	0.5%	$1,079	-$18	-1.6%
Variable Production Cost ($/MWh)	$33.42	$33.53	$0.11	0.3%	$33.56	$0.14	0.4%
CO_2 Emissions (Million Metric Tons)	213	213	0	0.0%	213	0	0.0%
Hg Emissions (Tons)	1	1	0	0.0%	1	0	-0.3%
NOx Emissions (Million Tons)	0	0	0	-0.5%	0	0	0.3%
SO_2 Emissions (Million Tons)	0	0	0	0.2%	0	0	-0.5%
HCL Emissions (Million Tons)	0	0	0	0.0%	0	0	-0.2%
Florida Reliability Coordinating Council (FRCC)							
Total Capacity (GW)	68	68	0	0.0%	68	0	0.0%
Existing			0	0.0%		0	0.0%
New Additions			0	0.0%		0	0.0%
Early Retirements			0	0.0%		0	0.0%
Electricity Prices ($/MWh)	$72.44	$72.67	$0.23	0.3%	$72.53	$0.09	0.1%
Generation (TWh)	271	271	0	0.0%	271	0	0.0%
Costs ($Millions)	$15,340	$15,389	$49	0.3%	$15,374	$33	0.2%
Fuel Cost	$10,216	$10,247	$31	0.3%	$10,223	$7	0.1%
Variable O&M	$874	$880	$6	0.7%	$883	$9	1.1%
Fixed O&M	$2,488	$2,500	$12	0.5%	$2,505	$17	0.7%
Capital Cost	$1,763	$1,763	$0	0.0%	$1,763	$0	0.0%
Variable Production Cost ($/MWh)	$40.97	$41.11	$0.14	0.3%	$41.03	$0.05	0.1%
CO_2 Emissions (Million Metric Tons)	129	129	0	0.0%	129	0	0.0%
Hg Emissions (Tons)	0	0	0	0.1%	0	0	0.1%
NOx Emissions (Million Tons)	0	0	0	0.0%	0	0	0.0%
SO_2 Emissions (Million Tons)	0	0	0	-1.9%	0	0	-2.2%
HCL Emissions (Million Tons)	0	0	0	1.6%	0	0	1.9%
Midwest Reliability Organization (MRO)							
Total Capacity (GW)	76	76	0	0.0%	76	0	0.0%
Existing			0	0.0%		0	0.0%
New Additions			0	0.0%		0	0.0%
Early Retirements			0	0.0%		0	0.0%
Electricity Prices ($/MWh)	$61.73	$61.76	$0.03	0.1%	$61.67	-$0.05	-0.1%
Generation (TWh)	317	317	0	0.2%	317	1	0.2%
Costs ($Millions)	$13,606	$13,659	$53	0.4%	$13,740	$134	1.0%
Fuel Cost	$5,977	$5,981	$4	0.1%	$5,982	$6	0.1%
Variable O&M	$1,201	$1,215	$14	1.2%	$1,246	$45	3.8%
Fixed O&M	$4,206	$4,246	$41	1.0%	$4,297	$91	2.2%
Capital Cost	$2,223	$2,217	-$6	-0.3%	$2,215	-$8	-0.4%
Variable Production Cost ($/MWh)	$22.67	$22.69	$0.02	0.1%	$22.78	$0.11	0.5%
CO_2 Emissions (Million Metric Tons)	208	208	-1	-0.3%	208	0	-0.2%
Hg Emissions (Tons)	1	1	0	-0.3%	1	0	-0.3%
NOx Emissions (Million Tons)	0	0	0	-0.2%	0	0	0.3%
SO_2 Emissions (Million Tons)	0	0	0	-0.3%	0	0	-0.2%
HCL Emissions (Million Tons)	0	0	0	0.4%	0	0	0.4%
Northeast Power Coordinating Council (NPCC)							
Total Capacity (GW)	73	73	0	0.0%	74	0	0.6%
Existing			0	0.0%		0	0.6%
New Additions			0	0.0%		0	0.0%
Early Retirements			0	0.0%		0	-0.6%
Electricity Prices ($/MWh)	$71.52	$71.71	$0.19	0.3%	$71.57	$0.04	0.1%
Generation (TWh)	264	264	0	0.0%	264	0	0.0%
Costs ($Millions)	$13,312	$13,327	$15	0.1%	$13,344	$32	0.2%
Fuel Cost	$7,291	$7,304	$14	0.2%	$7,288	-$3	0.0%
Variable O&M	$906	$908	$2	0.2%	$915	$9	1.0%
Fixed O&M	$4,151	$4,153	$2	0.0%	$4,174	$23	0.6%
Capital Cost	$965	$962	-$2	-0.3%	$967	$3	0.3%
Variable Production Cost ($/MWh)	$31.08	$31.14	$0.06	0.2%	$31.11	$0.03	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 $2010)	Baseline Value	Option 3 Value	Option 3 Difference	Option 3 % Change	Option 4 Value	Option 4 Difference	Option 4 % Change
CO_2 Emissions (Million Metric Tons)	79	79	0	0.0%	79	0	0.0%
Hg Emissions (Tons)	0	0	0	0.0%	0	0	0.0%
NOx Emissions (Million Tons)	0	0	0	0.0%	0	0	0.0%
SO_2 Emissions (Million Tons)	0	0	0	0.0%	0	0	0.0%
HCL Emissions (Million Tons)	0	0	0	0.0%	0	0	0.0%
ReliabilityFirst Corporation (RFC)							
Total Capacity (GW)	237	237	0	0.0%	237	0	-0.1%
Existing			0	0.0%		-1	-0.3%
New Additions			0	0.0%		1	0.2%
Early Retirements			0	0.0%		1	0.3%
Electricity Prices ($/MWh)	$64.64	$64.83	$0.19	0.3%	$64.79	$0.15	0.2%
Generation (TWh)	1,112	1,112	1	0.1%	1,112	1	0.1%
Costs ($Millions)	$54,665	$54,941	$276	0.5%	$55,469	$804	1.5%
Fuel Cost	$26,453	$26,493	$40	0.1%	$26,463	$10	0.0%
Variable O&M	$3,445	$3,562	$117	3.4%	$3,777	$332	9.6%
Fixed O&M	$17,082	$17,195	$113	0.7%	$17,485	$403	2.4%
Capital Cost	$7,685	$7,692	$7	0.1%	$7,745	$60	0.8%
Variable Production Cost ($/MWh)	$26.90	$27.02	$0.12	0.5%	$27.18	$0.29	1.1%
CO_2 Emissions (Million Metric Tons)	641	641	0	0.1%	639	-1	-0.2%
Hg Emissions (Tons)	3	3	0	-0.1%	3	0	-0.3%
NOx Emissions (Million Tons)	1	1	0	0.3%	1	0	0.0%
SO_2 Emissions (Million Tons)	1	1	0	-0.1%	1	0	-0.3%
HCL Emissions (Million Tons)	0	0	0	0.3%	0	0	0.1%
Southeast Electric Reliability Council (SERC)							
Total Capacity (GW)	274	274	0	0.0%	274	0	0.0%
Existing			0	0.0%		0	0.0%
New Additions			0	0.0%		0	0.0%
Early Retirements			0	0.0%		0	0.0%
Electricity Prices ($/MWh)	$63.63	$63.87	$0.24	0.4%	$63.82	$0.19	0.3%
Generation (TWh)	1,239	1,238	-1	-0.1%	1,237	-2	-0.1%
Costs ($Millions)	$56,058	$56,380	$322	0.6%	$56,719	$662	1.2%
Fuel Cost	$31,341	$31,337	-$3	0.0%	$31,286	-$55	-0.2%
Variable O&M	$3,896	$4,079	$183	4.7%	$4,256	$360	9.2%
Fixed O&M	$16,415	$16,567	$152	0.9%	$16,785	$371	2.3%
Capital Cost	$4,406	$4,398	-$9	-0.2%	$4,393	-$13	-0.3%
Variable Production Cost ($/MWh)	$28.44	$28.61	$0.17	0.6%	$28.72	$0.28	1.0%
CO_2 Emissions (Million Metric Tons)	695	694	-1	-0.2%	693	-2	-0.3%
Hg Emissions (Tons)	2	2	0	-0.2%	2	0	-1.0%
NOx Emissions (Million Tons)	0	0	0	-0.1%	0	0	-0.3%
SO_2 Emissions (Million Tons)	1	1	0	-0.1%	1	0	0.0%
HCL Emissions (Million Tons)	0	0	0	-0.2%	0	0	0.1%
Southwest Power Pool (SPP)							
Total Capacity (GW)	59	60	1	0.8%	60	0	0.6%
Existing			0	0.7%		0	0.6%
New Additions			0	0.1%		0	0.0%
Early Retirements			0	-0.7%		0	-0.6%
Electricity Prices ($/MWh)	$59.65	$59.82	$0.17	0.3%	$59.75	$0.09	0.2%
Generation (TWh)	237	237	0	0.0%	237	0	-0.1%
Costs ($Millions)	$10,307	$10,342	$35	0.3%	$10,379	$72	0.7%
Fuel Cost	$6,067	$6,079	$11	0.2%	$6,067	-$1	0.0%
Variable O&M	$960	$967	$8	0.8%	$988	$28	2.9%
Fixed O&M	$2,409	$2,421	$12	0.5%	$2,462	$53	2.2%
Capital Cost	$871	$875	$3	0.4%	$863	-$8	-0.9%
Variable Production Cost ($/MWh)	$29.63	$29.71	$0.08	0.3%	$29.79	$0.15	0.5%
CO_2 Emissions (Million Metric Tons)	169	169	0	0.0%	169	0	-0.2%
Hg Emissions (Tons)	1	1	0	0.0%	0	0	-0.3%
NOx Emissions (Million Tons)	0	0	0	1.0%	0	0	1.2%
SO_2 Emissions (Million Tons)	0	0	0	0.0%	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 $2010)	Baseline Value	Option 3			Option 4		
		Value	Difference	% Change	Value	Difference	% Change
HCL Emissions (Million Tons)	0	0	0	0.0%	0	0	-0.3%
Western Electricity Coordinating Council (WECC)							
Total Capacity (GW)	220	220	0	0.0%	220	0	0.0%
Existing			0	0.0%		0	0.0%
New Additions			0	0.0%		0	0.0%
Early Retirements			0	0.0%		0	0.0%
Electricity Prices ($/MWh)	$63.57	$63.73	$0.15	0.2%	$63.61	$0.04	0.1%
Generation (TWh)	869	869	0	0.0%	869	0	0.0%
Costs ($Millions)	$36,811	$36,862	$50	0.1%	$36,863	$52	0.1%
Fuel Cost	$18,390	$18,426	$35	0.2%	$18,395	$5	0.0%
Variable O&M	$3,230	$3,236	$6	0.2%	$3,253	$23	0.7%
Fixed O&M	$8,254	$8,258	$5	0.1%	$8,277	$24	0.3%
Capital Cost	$6,938	$6,942	$4	0.1%	$6,938	$0	0.0%
Variable Production Cost ($/MWh)	$24.87	$24.92	$0.05	0.2%	$24.90	$0.03	0.1%
CO_2 Emissions (Million Metric Tons)	317	317	0	0.0%	317	0	0.0%
Hg Emissions (Tons)	2	2	0	0.0%	2	0	0.0%
NOx Emissions (Million Tons)	0	0	0	0.0%	0	0	0.0%
SO_2 Emissions (Million Tons)	0	0	0	-0.1%	0	0	0.3%
HCL Emissions (Million Tons)	0	0	0	0.1%	0	0	0.0%

a. Numbers may not add up due to rounding.
Source: U.S. EPA Analysis, 2013

Findings for Regulatory Option 3

As reported in *Table 5-1*, the Market Model Analysis indicates that Option 3 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 an addition of approximately 1GW in capacity (less than 0.05 percent total market capacity). This increase is expected to take place entirely in the SPP NERC region (0.08 percent of total SPP capacity) and is the result of reduction in retired capacity (avoided capacity closures) and increase in new capacity and capacity at existing generating units. Consequently, Option 3 is expected to have negligible effect on capacity availability and supply reliability at the national level. Overall impacts on electricity prices are similarly minimal. While electricity prices are expected to increase in all NERC regions, the magnitude of this increase varies across regions and ranges from $0.03 per MWh (0.1 percent) in MRO to $0.24 per MWh (0.4 percent) in SERC. Finally, at the national level, total costs increase by approximately 0.4 percent. Across regions, no NERC region records an increase in power sector total costs exceeding 1 percent.

At the national level, the change in emissions is small relative to baseline emissions; CO_2, SO_2, and Hg emissions decrease by 0.1 percent, while NOx and HCL emissions increase by 0.1 percent. The impact on emissions varies across regions. Emissions increase in some and decrease in other NERC regions; however, generally the change does not exceed 2 percent.[78]

Findings for Regulatory Option 4

Option 4 shows small effects *overall*. The net change in total capacity under Option 4 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 in RFC (due to early retirement) and SPP (due to avoided retirement). Option 4 also has a small impact on

[78] 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).

electricity prices across all NERC regions, with increases of no more than 0.3 percent and a 0.1 percent reduction in the MRO region. At the national level, variable production costs – fuel and variable O&M – increase by a small amount of $0.18 per MWh or 0.6 percent. While variable costs increase in all NERC regions, the magnitude of the change depends on the region and ranges from $0.03 in NPCC and WECC (0.1 percent) to $0.29 in RFC (1.1 percent). As expected for Option 4, which is more expensive than Option 3, the increase in total annual costs for the electric power sector is greater than under Option 3, but the increase is still modest. At the national level, total annual costs increase by $1.9 billion (0.9 percent). The larger parts of this increase occur in variable O&M; capital costs increase by a much smaller amount.

At the national level, emissions of CO_2 and SO_2 decline by 0.2 percent and Hg emissions decline by 0.4 percent; NOx and HCL emissions increase by 0.1 percent.[79]

Impact on Steam Electric Plants as a Group

For the analysis of impact on steam electric plants as a group, EPA used the same IPM V4.10 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 only on the steam electric plants (i.e., 665 plants). The purpose of the previously described electricity market-level analysis is to assess the impact of the options analyzed in support of the proposed ELGs on the entire electric power sector, i.e., including plants that are not subject to the proposed ELGs. By contrast, the purpose of this analysis is to assess the impact of the regulatory options specifically on steam electric plants. The analysis results for the group of steam electric plants (*Table 5-2*) overall show a slightly greater impact 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 reflect only the economic activities of the 665 steam electric plants analyzed in IPM. 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 regulation on emissions and are therefore not presented, and (3) the number of steam electric plants with projected closure is presented.

The following four measures are reported in the analysis of steam electric plants as a group. In all instances, the measures are tabulated only for the 665 steam electric plants that are analyzed in the Market Model Analysis:

- *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 a reduction in available capacity (see discussion above) or less frequent dispatch of a plant due to higher production cost resulting from compliance response. At the same time, the proposed ELG options may lead to an increase in generation for some steam electric plants if their compliance costs are low relative to other steam electric plants.
- *Changes in costs*: These changes are defined in the same way as in the preceding section (Impact on National and Regional Electricity Markets).

[79] 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).

- *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 plants, as a group.

The impacts of the regulatory options on steam electric 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. However, in the same way as described above for the market-level analysis, the impacts of Option 3 are generally smaller than those of Options 4.

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

Economic Measures (all dollar values in $2010)	Baseline Value	Option 3			Option 4		
		Value	Difference	% Change	Value	Difference	% Change
National Totals							
Total Capacity (MW)	455,894	456,000	106	0.0%	455,588	-306	-0.1%
Early Retirements – Number of Plants	23	23	0	0.0%	23	0	0.0%
Full and Partial Retirements – Capacity (MW)	21,887	21,785	-102	-0.5%	22,204	317	1.4%
Generation (GWh)	2,479,179	2,478,225	-954	0.0%	2,474,262	-4,916	-0.2%
Costs ($Millions)	$109,026	$109,668	$642	0.6%	$110,530	$1,504	1.4%
Fuel Cost	$63,671	$63,629	-$42	-0.1%	$63,398	-$273	-0.4%
Variable O&M	$8,911	$9,260	$348	3.9%	$9,737	$825	9.3%
Fixed O&M	$32,024	$32,378	$354	1.1%	$33,039	$1,015	3.2%
Capital Cost	$4,420	$4,402	-$18	-0.4%	$4,357	-$63	-1.4%
Variable Production Cost ($/MWh)	$29.28	$29.41	$0.13	0.5%	$29.56	$0.28	1.0%
Electric Reliability Council of Texas (ERCOT)							
Total Capacity (MW)	32,275	32,275	0	0.0%	32,275	0	0.0%
Early Retirements – Number of Plants	1	1	0	0.0%	1	0	0.0%
Full and Partial Retirements – Capacity (MW)	244	244	0	0.0%	244	0	0.0%
Generation (GWh)	166,917	166,834	-83	0.0%	166,690	-227	-0.1%
Costs ($Millions)	$6,769	$6,805	$35	0.5%	$6,836	$66	1.0%
Fuel Cost	$4,125	$4,122	-$4	-0.1%	$4,113	-$12	-0.3%
Variable O&M	$785	$801	$16	2.1%	$817	$32	4.1%
Fixed O&M	$1,828	$1,851	$23	1.3%	$1,874	$46	2.5%
Capital Cost	$32	$31	$0	-1.4%	$32	$0	0.1%
Variable Production Cost ($/MWh)	$29.42	$29.51	$0.09	0.3%	$29.58	$0.16	0.5%
Florida Reliability Coordinating Council (FRCC)							
Total Capacity (MW)	32,227	32,227	0	0.0%	32,227	0	0.0%
Early Retirements – Number of Plants	0	0	0	NA	0	0	NA
Full and Partial Retirements – Capacity (MW)	0	0	0	NA	0	0	NA
Generation (GWh)	140,864	140,839	-25	0.0%	140,942	78	0.1%
Costs ($Millions)	$6,964	$6,991	$27	0.4%	$6,991	$27	0.4%
Fuel Cost	$4,810	$4,819	$9	0.2%	$4,811	$1	0.0%
Variable O&M	$468	$474	$6	1.2%	$477	$9	2.0%
Fixed O&M	$1,641	$1,653	$12	0.7%	$1,657	$17	1.0%
Capital Cost	$46	$46	$0	0.0%	$46	$0	0.0%
Variable Production Cost ($/MWh)	$37.47	$37.58	$0.11	0.3%	$37.52	$0.05	0.1%
Midwest Reliability Organization (MRO)							
Total Capacity (MW)	34,899	34,902	2	0.0%	34,902	3	0.0%
Early Retirements – Number of Plants	0	0	0	NA	0	0	NA

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

Economic Measures (all dollar values in $2010)	Baseline Value	Option 3			Option 4		
		Value	Difference	% Change	Value	Difference	% Change
Full and Partial Retirements – Capacity (MW)	359	359	0	0.0%	359	0	0.0%
Generation (GWh)	206,980	207,063	83	0.0%	207,192	212	0.1%
Costs ($Millions)	$7,966	$7,993	$26	0.3%	$8,075	$108	1.4%
Fuel Cost	$3,916	$3,900	-$16	-0.4%	$3,903	-$13	-0.3%
Variable O&M	$855	$868	$13	1.5%	$899	$44	5.1%
Fixed O&M	$2,826	$2,867	$40	1.4%	$2,917	$91	3.2%
Capital Cost	$369	$358	-$11	-3.0%	$356	-$13	-3.6%
Variable Production Cost ($/MWh)	$23.05	$23.03	-$0.02	-0.1%	$23.17	$0.12	0.5%
Northeast Power Coordinating Council (NPCC)							
Total Capacity (MW)	16,629	16,629	0	0.0%	17,060	431	2.6%
Early Retirements – Number of Plants	2	2	0	0.0%	2	0	0.0%
Full and Partial Retirements – Capacity (MW)	1,975	1,975	0	0.0%	1,544	-431	-21.8%
Generation (GWh)	80,459	80,456	-3	0.0%	80,455	-4	0.0%
Costs ($Millions)	$4,396	$4,405	$9	0.2%	$4,425	$29	0.7%
Fuel Cost	$2,760	$2,764	$4	0.1%	$2,759	-$1	0.0%
Variable O&M	$247	$248	$2	0.7%	$256	$9	3.8%
Fixed O&M	$1,314	$1,317	$3	0.3%	$1,334	$21	1.6%
Capital Cost	$75	$75	$0	0.0%	$75	$0	0.0%
Variable Production Cost ($/MWh)	$37.37	$37.44	$0.07	0.2%	$37.47	$0.10	0.3%
ReliabilityFirst Corporation (RFC)							
Total Capacity (MW)	122,205	122,205	0	0.0%	121,527	-678	-0.6%
Early Retirements – Number of Plants	3	3	0	0.0%	3	0	0.0%
Full and Partial Retirements – Capacity (MW)	4,520	4,520	0	0.0%	5,201	681	15.1%
Generation (GWh)	696,666	696,899	234	0.0%	694,314	-2,351	-0.3%
Costs ($Millions)	$31,577	$31,802	$225	0.7%	$32,138	$561	1.8%
Fuel Cost	$17,960	$17,957	-$3	0.0%	$17,831	-$129	-0.7%
Variable O&M	$2,338	$2,454	$116	5.0%	$2,661	$324	13.8%
Fixed O&M	$9,575	$9,687	$112	1.2%	$9,968	$393	4.1%
Capital Cost	$1,705	$1,705	$0	0.0%	$1,679	-$26	-1.5%
Variable Production Cost ($/MWh)	$29.14	$29.29	$0.15	0.5%	$29.51	$0.38	1.3%
Southeast Electric Reliability Council (SERC)							
Total Capacity (MW)	131,895	131,896	2	0.0%	131,802	-93	-0.1%
Early Retirements – Number of Plants	7	7	0	0.0%	7	0	0.0%
Full and Partial Retirements – Capacity (MW)	8,383	8,383	0	0.0%	8,480	97	1.2%
Generation (GWh)	739,611	738,471	-1,140	-0.2%	737,433	-2,178	-0.3%
Costs ($Millions)	$33,277	$33,560	$283	0.8%	$33,884	$607	1.8%
Fuel Cost	$19,472	$19,432	-$39	-0.2%	$19,369	-$103	-0.5%
Variable O&M	$2,517	$2,699	$182	7.2%	$2,873	$357	14.2%
Fixed O&M	$9,646	$9,792	$146	1.5%	$10,016	$370	3.8%
Capital Cost	$1,643	$1,637	-$6	-0.4%	$1,625	-$17	-1.1%
Variable Production Cost ($/MWh)	$29.73	$29.97	$0.24	0.8%	$30.16	$0.43	1.5%
Southwest Power Pool (SPP)							
Total Capacity (MW)	31,269	31,371	102	0.3%	31,300	31	0.1%
Early Retirements – Number of Plants	3	3	0	0.0%	3	0	0.0%
Full and Partial Retirements – Capacity (MW)	1,733	1,631	-102	-5.9%	1,703	-30	-1.7%
Generation (GWh)	159,184	159,062	-123	-0.1%	158,675	-510	-0.3%

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

Economic Measures (all dollar values in $2010)	Baseline Value	Option 3			Option 4		
		Value	Difference	% Change	Value	Difference	% Change
Costs ($Millions)	$6,548	$6,563	$15	0.2%	$6,606	$59	0.9%
Fuel Cost	$3,571	$3,566	-$5	-0.1%	$3,557	-$15	-0.4%
Variable O&M	$715	$723	$7	1.0%	$742	$27	3.7%
Fixed O&M	$1,867	$1,880	$13	0.7%	$1,920	$54	2.9%
Capital Cost	$394	$393	-$1	-0.2%	$387	-$7	-1.8%
Variable Production Cost ($/MWh)	$26.93	$26.97	$0.04	0.1%	$27.09	$0.16	0.6%
Western Electricity Coordinating Council (WECC)							
Total Capacity (MW)	54,494	54,494	0	0.0%	54,494	0	0.0%
Early Retirements – Number of Plants	7	7	0	0.0%	7	0	0.0%
Full and Partial Retirements – Capacity (MW)	4,672	4,672	0	0.0%	4,672	0	0.0%
Generation (GWh)	288,497	288,600	103	0.0%	288,560	63	0.0%
Costs ($Millions)	$11,529	$11,551	$22	0.2%	$11,575	$46	0.4%
Fuel Cost	$7,057	$7,068	$11	0.2%	$7,056	-$1	0.0%
Variable O&M	$987	$994	$7	0.7%	$1,011	$24	2.4%
Fixed O&M	$3,328	$3,332	$4	0.1%	$3,352	$24	0.7%
Capital Cost	$157	$157	$0	0.0%	$157	$0	0.0%
Variable Production Cost ($/MWh)	$27.88	$27.93	$0.05	0.2%	$27.95	$0.07	0.3%

a. Numbers may not add up due to rounding.
Source: U.S. EPA Analysis, 2013

Findings for Regulatory Option 3

Under Option 3, as is the case for the electricity market as a whole, the net change in total capacity for the group of steam electric plants is small.

For the group of steam electric plants, total capacity increases by 106 MW or approximately 0.02 percent of the 455,894 MW baseline capacity. This results in part from *avoided* capacity closures of 102 MW in the SPP region. Option 3 results in no closures – full (plant) or partial (unit) – in any of the NERC regions.

The change in total generation is an indicator of how steam electric 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,[80] for steam electric plants, total available capacity and electricity generation at the national level is projected to fall by less than 0.1 percent. At the regional level, five NERC regions – ERCOT, NPCC, RFC, SERC, and SPP – are projected to experience a reduction in electricity generation from steam electric plants, ranging from 3 GWh in NPCC (less than 0.01 percent) to 1,140 GWh in RFC (0.2 percent). The other three NERC regions each are projected to experience a small increase in electricity generation from steam electric plants of less than 0.1 percent.

At the national level, variable production costs at steam electric plants increase by approximately 0.5 percent. These effects vary by region from about -0.1 percent in MRO to 0.8 percent in SERC. These findings confirm EPA‟s assessment that Option 3 can be expected to have little economic consequence in national and regional electricity markets.

Findings for Regulatory Option 4

Results of the analysis for Option 4 show small reductions in steam electric generating capacity and electricity generation of 306 MW (0.07 percent) and 4,916 GWh (0.2 percent), respectively. The steam electric capacity

[80] 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.

reduction includes early retirement and avoided retirement of generating units with the net effect of the two types of changes being capacity losses. Thus, under the analysis for this option, 14 generating units close (1,125 MW) and 5 generating units avoid closure (808 MW), leading to an estimated net closure of nine generating units (317 MW). All 14 units that are projected to close are located within six plants that otherwise remain open. In other words, Option 4 is not projected to result in any full plant closures.

Findings for the change in total costs and variable production costs under this Option exceed those under Option 3 but remain modest. The model projects a 1.4 percent increase in total costs at the national level in 2030, with the SERC region recording the largest increase of 1.8 percent. At the national level, the increase in total costs occurs in fixed and variable O&M (3.2 percent and 9.3 percent, respectively) while fuel costs and capital costs decline (0.4 percent and 3.2 percent, respectively). Variable production costs increase by 1.0 percent, with the SERC region recording the highest increase of 1.5 percent.

Impact on Individual Steam Electric Plants

Results *for the group* of steam electric plants as a whole may mask shifts in economic performance among *individual* steam electric 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 5-3 presents the estimated number of steam electric 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 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, 101 and 104 plants are excluded from assessment of effects on individual steam electric plants under Options 3 and 4, respectively.

In addition, the change in variable production cost per MWh of generation could not be developed for 14 plants with zero generation in either baseline or post-compliance cases under Options 3 and 4. 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 5-3: Impact of Market Impact Analysis Options on Individual Steam Electric Plants at the Year 2030 (number of steam electric plants with indicated effect)

	Reduction				Increase			
Economic Measures	≥ 3%	≥1% and <3%	<1%	No Change	<1%	≥1% and <3%	≥ 3%	N/A[b,c]
Option 3								
Change in Capacity Utilization[a]	6	7	62	438	41	4	6	101
Change in Generation	15	3	53	443	38	4	8	101
Change in Variable Production Costs/MWh	2	3	183	72	239	28	23	115

Table 5-3: Impact of Market Impact Analysis Options on Individual Steam Electric Plants at the Year 2030 (number of steam electric plants with indicated effect)

Economic Measures	Reduction ≥ 3%	Reduction ≥1% and <3%	Reduction <1%	No Change	Increase <1%	Increase ≥1% and <3%	Increase ≥ 3%	N/A[b,c]
Option 4								
Change in Capacity Utilization[a]	6	4	131	291	113	7	9	104
Change in Generation	12	4	118	302	104	6	15	104
Change in Variable Production Costs/MWh	2	2	136	46	225	99	37	118

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 status changes in either baseline or post-compliance scenario have been excluded from these calculations. Specifically, there are 23 full baseline plant closures, 77 partial baseline plant closures, and 1 avoided plant closure under Option 3. There are 23 full baseline plant closures, 72 partial baseline plant closures, 3 avoided plant closures, and 6 partial policy plant closures under Option 4.
c. The change in variable production cost per MWh could not be developed for 14 plants with zero generation in either the baseline case or Options 3 or 4 post-compliance cases.
Source: U.S. EPA Analysis, 2013

Findings for Regulatory Option 3

For Option 3, 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 13 plants (2 percent) are estimated to incur a reduction in capacity utilization of at least 1 percent and 18 plants (3 percent) incur a reduction in generation of at least 1 percent.[81] The estimated change in variable production costs is higher; for 51 plants (8 percent) variable production costs are expected to increase by at least 1 percent and for more than 50 percent of these plants this increase is at least 1 percent but less than 3 percent.

Findings for Regulatory Option 4

Under Option 4, the analysis indicates that most plants experience only slight effects, though these effects are greater than for Option 3. Option 4 shows small reductions in capacity utilization and generation; only 10 and 16 plants (approximately 2 percent) incur more than a 1 percent reduction in capacity utilization and generation, respectively. Impacts on variable costs are larger than for Option 3, but still modest. The increase in variable production costs is estimated to exceed 1 percent for 136 plants, 99 of which have an increase of at least 1 percent but less than 3 percent. However, the vast majority of steam electric 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 Proposed ELGs

This section presents market-level results for the proposed ELG options for the 2020 model run year, which represents the years 2017 through 2024. As discussed above, this run year captures the period when steam electric plants would be implementing compliance technologies. Higher electricity production costs at steam electric plants due to compliance with the proposed 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 plants.

Table 5-4 presents the following national and NERC-region market-level impacts for 2020:

- Electricity price changes, including changes in energy prices and capacity prices

81 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.

- 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 5-4 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 three regulatory options focuses on these differences.

Table 5-4: Short-Term Effect of Compliance with Regulatory Options on National Electricity Market - 2020[a]

Economic Measures (all dollar values in $2010)	Baseline Value	Option 3 Value	Option 3 Difference	Option 3 % Change	Option 4 Value	Option 4 Difference	Option 4 % Change
National Totals							
Electricity Prices ($/MWh)	NA	NA	NA	NA	NA	NA	NA
Generation (TWh)	4,304	4,304	0	0.0%	4,303	-1	0.0%
Costs ($Millions)	$171,334	$172,011	$677	0.4%	$173,299	$1,965	1.1%
Fuel Cost	$89,869	$89,847	-$23	0.0%	$90,003	$133	0.1%
Variable O&M	$14,738	$15,083	$346	2.3%	$15,561	$823	5.6%
Fixed O&M	$52,855	$53,215	$359	0.7%	$53,877	$1,022	1.9%
Capital Cost	$13,872	$13,866	-$5	0.0%	$13,858	-$14	-0.1%
Variable Production Cost ($/MWh)	$24.30	$24.38	$0.08	0.3%	$24.53	$0.23	0.9%
CO_2 Emissions (Million Metric Tonnes)	2,293	2,291	-1	-0.1%	2,290	-3	-0.1%
Mercury Emissions (Tons)	9	9	0	-0.1%	9	0	-0.2%
NOx Emissions (Million Tons)	2	2	0	0.1%	2	0	0.1%
SO_2 Emissions (Million Tons)	2	2	0	-0.1%	2	0	0.0%
HCL Emissions (Million Tons)	0	0	0	0.3%	0	0	0.4%
Electric Reliability Council of Texas (ERCOT)							
Electricity Prices ($/MWh)	$48.16	$48.22	$0.07	0.1%	$48.45	$0.30	0.6%
Generation (TWh)	346	346	0	0.0%	346	0	0.0%
Costs ($Millions)	$13,064	$13,110	$46	0.4%	$13,171	$106	0.8%
Fuel Cost	$8,335	$8,339	$4	0.0%	$8,351	$16	0.2%
Variable O&M	$1,323	$1,340	$18	1.3%	$1,365	$43	3.2%
Fixed O&M	$3,249	$3,274	$25	0.8%	$3,297	$48	1.5%
Capital Cost	$157	$157	-$1	-0.4%	$157	$0	0.0%
Variable Production Cost ($/MWh)	$27.87	$27.94	$0.06	0.2%	$28.04	$0.17	0.6%
CO_2 Emissions (Million Metric Tonnes)	194	194	0	0.0%	194	0	0.2%
Mercury Emissions (Tons)	1	1	0	0.6%	1	0	0.2%
NOx Emissions (Million Tons)	0	0	0	-0.3%	0	0	0.7%
SO_2 Emissions (Million Tons)	0	0	0	0.6%	0	0	-1.4%
HCL Emissions (Million Tons)	0	0	0	0.1%	0	0	-0.2%
Florida Reliability Coordinating Council (FRCC)							
Electricity Prices ($/MWh)	$57.89	$58.00	$0.11	0.2%	$58.21	$0.32	0.6%
Generation (TWh)	237	237	0	0.0%	237	0	0.1%
Costs ($Millions)	$10,761	$10,788	$27	0.2%	$10,827	$66	0.6%
Fuel Cost	$7,685	$7,692	$7	0.1%	$7,720	$35	0.5%
Variable O&M	$814	$822	$8	0.9%	$829	$15	1.8%
Fixed O&M	$2,096	$2,108	$12	0.6%	$2,113	$17	0.8%
Capital Cost	$166	$166	$0	0.0%	$166	$0	0.0%
Variable Production Cost ($/MWh)	$35.92	$35.97	$0.05	0.1%	$36.10	$0.18	0.5%
CO_2 Emissions (Million Metric Tonnes)	119	119	0	0.1%	120	1	0.6%
Mercury Emissions (Tons)	0	0	0	0.2%	0	0	0.7%
NOx Emissions (Million Tons)	0	0	0	0.2%	0	0	0.6%
SO_2 Emissions (Million Tons)	0	0	0	0.2%	0	0	0.7%
HCL Emissions (Million Tons)	0	0	0	0.3%	0	0	1.6%

Table 5-4: Short-Term Effect of Compliance with Regulatory Options on National Electricity Market - 2020[a]

Economic Measures (all dollar values in $2010)	Baseline Value	Option 3 Value	Option 3 Difference	Option 3 % Change	Option 4 Value	Option 4 Difference	Option 4 % Change
Midwest Reliability Organization (MRO)							
Electricity Prices ($/MWh)	$50.64	$50.75	$0.10	0.2%	$50.95	$0.31	0.6%
Generation (TWh)	286	286	0	0.0%	286	0	0.0%
Costs ($Millions)	$10,571	$10,592	$21	0.2%	$10,658	$87	0.8%
Fuel Cost	$4,655	$4,638	-$17	-0.4%	$4,646	-$9	-0.2%
Variable O&M	$1,066	$1,079	$13	1.2%	$1,107	$41	3.8%
Fixed O&M	$3,878	$3,918	$40	1.0%	$3,966	$87	2.3%
Capital Cost	$972	$957	-$14	-1.5%	$940	-$32	-3.3%
Variable Production Cost ($/MWh)	$19.98	$19.96	-$0.02	-0.1%	$20.08	$0.10	0.5%
CO_2 Emissions (Million Metric Tonnes)	198	197	-1	-0.4%	198	0	-0.2%
Mercury Emissions (Tons)	1	1	0	0.3%	1	0	-0.1%
NOx Emissions (Million Tons)	0	0	0	0.0%	0	0	0.5%
SO_2 Emissions (Million Tons)	0	0	0	0.5%	0	0	0.9%
HCL Emissions (Million Tons)	0	0	0	4.1%	0	0	4.1%
Northeast Power Coordinating Council (NPCC)							
Electricity Prices ($/MWh)	$52.53	$52.59	$0.07	0.1%	$52.82	$0.29	0.6%
Generation (TWh)	259	259	0	0.0%	259	0	0.0%
Costs ($Millions)	$11,329	$11,341	$12	0.1%	$11,384	$55	0.5%
Fuel Cost	$5,513	$5,522	$8	0.2%	$5,537	$23	0.4%
Variable O&M	$855	$856	$2	0.2%	$864	$9	1.1%
Fixed O&M	$4,280	$4,283	$2	0.1%	$4,303	$23	0.5%
Capital Cost	$681	$680	$0	0.0%	$680	$0	0.0%
Variable Production Cost ($/MWh)	$24.58	$24.62	$0.03	0.1%	$24.71	$0.12	0.5%
CO_2 Emissions (Million Metric Tonnes)	70	70	0	0.0%	70	0	0.0%
Mercury Emissions (Tons)	0	0	0	0.0%	0	0	0.1%
NOx Emissions (Million Tons)	0	0	0	0.0%	0	0	0.1%
SO_2 Emissions (Million Tons)	0	0	0	0.9%	0	0	1.4%
HCL Emissions (Million Tons)	0	0	0	0.1%	0	0	0.0%
ReliabilityFirst Corporation (RFC)							
Electricity Prices ($/MWh)	$48.35	$48.47	$0.13	0.3%	$48.80	$0.45	0.9%
Generation (TWh)	1,025	1,025	0	0.0%	1,026	0	0.0%
Costs ($Millions)	$44,528	$44,740	$212	0.5%	$45,297	$769	1.7%
Fuel Cost	$21,509	$21,486	-$23	-0.1%	$21,536	$27	0.1%
Variable O&M	$3,154	$3,269	$115	3.6%	$3,474	$320	10.2%
Fixed O&M	$15,464	$15,577	$112	0.7%	$15,862	$398	2.6%
Capital Cost	$4,401	$4,409	$8	0.2%	$4,424	$24	0.5%
Variable Production Cost ($/MWh)	$24.05	$24.14	$0.09	0.4%	$24.38	$0.33	1.4%
CO_2 Emissions (Million Metric Tonnes)	605	605	0	0.1%	604	-1	-0.2%
Mercury Emissions (Tons)	2	2	0	-0.1%	2	0	-0.4%
NOx Emissions (Million Tons)	1	1	0	0.4%	1	0	0.0%
SO_2 Emissions (Million Tons)	1	1	0	0.0%	1	0	-0.2%
HCL Emissions (Million Tons)	0	0	0	0.1%	0	0	0.0%
Southeast Electric Reliability Council (SERC)							
Electricity Prices ($/MWh)	$48.30	$48.44	$0.14	0.3%	$48.71	$0.41	0.9%
Generation (TWh)	1,142	1,141	-1	0.0%	1,140	-2	-0.1%
Costs ($Millions)	$45,321	$45,641	$320	0.7%	$46,016	$695	1.5%
Fuel Cost	$24,635	$24,624	-$11	0.0%	$24,619	-$16	-0.1%
Variable O&M	$3,611	$3,788	$176	4.9%	$3,954	$343	9.5%
Fixed O&M	$14,704	$14,857	$153	1.0%	$15,076	$372	2.5%
Capital Cost	$2,370	$2,373	$3	0.1%	$2,366	-$4	-0.2%
Variable Production Cost ($/MWh)	$24.74	$24.89	$0.16	0.6%	$25.06	$0.32	1.3%
CO_2 Emissions (Million Metric Tonnes)	649	648	-1	-0.2%	646	-2	-0.4%
Mercury Emissions (Tons)	2	2	0	-0.6%	2	0	-0.9%
NOx Emissions (Million Tons)	0	0	0	-0.4%	0	0	-0.6%
SO_2 Emissions (Million Tons)	1	1	0	-0.7%	1	0	-0.5%
HCL Emissions (Million Tons)	0	0	0	-0.3%	0	0	0.1%

Table 5-4: Short-Term Effect of Compliance with Regulatory Options on National Electricity Market - 2020[a]

Economic Measures (all dollar values in $2010)	Baseline Value	Option 3			Option 4		
		Value	Difference	% Change	Value	Difference	% Change
Southwest Power Pool (SPP)							
Electricity Prices ($/MWh)	$43.98	$44.10	$0.11	0.3%	$44.30	$0.31	0.7%
Generation (TWh)	221	221	0	0.0%	221	0	0.0%
Costs ($Millions)	$8,425	$8,446	$21	0.3%	$8,520	$96	1.1%
Fuel Cost	$4,743	$4,745	$2	0.1%	$4,757	$14	0.3%
Variable O&M	$919	$927	$8	0.9%	$949	$30	3.2%
Fixed O&M	$2,125	$2,137	$12	0.6%	$2,178	$53	2.5%
Capital Cost	$637	$637	-$1	-0.1%	$637	-$1	-0.1%
Variable Production Cost ($/MWh)	$25.57	$25.61	$0.04	0.2%	$25.76	$0.19	0.8%
CO_2 Emissions (Million Metric Tonnes)	161	161	0	0.0%	161	0	0.0%
Mercury Emissions (Tons)	0	0	0	-0.2%	0	0	0.0%
NOx Emissions (Million Tons)	0	0	0	1.2%	0	0	1.2%
SO_2 Emissions (Million Tons)	0	0	0	-1.0%	0	0	-0.3%
HCL Emissions (Million Tons)	0	0	0	-0.3%	0	0	-0.1%
Western Electricity Coordinating Council (WECC)							
Electricity Prices ($/MWh)	$48.82	$48.88	$0.06	0.1%	$49.06	$0.24	0.5%
Generation (TWh)	787	787	0	0.0%	787	0	0.0%
Costs ($Millions)	$27,335	$27,352	$17	0.1%	$27,426	$91	0.3%
Fuel Cost	$12,794	$12,800	$7	0.1%	$12,837	$44	0.3%
Variable O&M	$2,996	$3,002	$7	0.2%	$3,019	$23	0.8%
Fixed O&M	$7,058	$7,061	$4	0.1%	$7,081	$24	0.3%
Capital Cost	$4,488	$4,488	$0	0.0%	$4,488	$0	0.0%
Variable Production Cost ($/MWh)	$20.06	$20.08	$0.02	0.1%	$20.15	$0.09	0.4%
CO_2 Emissions (Million Metric Tonnes)	297	297	0	0.0%	297	0	0.0%
Mercury Emissions (Tons)	2	2	0	0.2%	2	0	0.4%
NOx Emissions (Million Tons)	0	0	0	0.0%	0	0	0.0%
SO_2 Emissions (Million Tons)	0	0	0	0.8%	0	0	1.7%
HCL Emissions (Million Tons)	0	0	0	0.2%	0	0	0.9%

a. Numbers may not add up due to rounding.

Source: U.S. EPA Analysis, 2013

Findings for Regulatory Option 3

As discussed earlier, steam electric plants are expected to implement control technologies during the 5-year period of 2017 through 2021, which falls in the range of years represented by the 2020 IPM run year (for details see *Appendix C*). Consequently, results for the year 2020 are indicative of annual effects during each of these years.

As shown in *Table 5-4*, the estimated effects of compliance-technology implementation under Option 3 are small. At the national level, total production costs increase by 0.4 percent; this increase is driven by higher variable and fixed O&M costs (2.3 percent and 0.7 percent increases, respectively). Capital and fuel costs decline by 0.04 percent and 0.03 percent, respectively. Total production costs increase in all NERC regions, with SERC recording the largest increase of 0.7 percent. At the regional level, the impact on production-cost components varies across NERC regions and by cost component, with some cost components increasing in some and declining in other regions; however, the change is generally small, except for 3.6 percent and 4.9 percent increases in variable O&M costs observed in the RFC and SERC regions, respectively.

At the national level, variable production costs ($/MWh) increase by approximately 0.3 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, one region – MRO – records a reduction in variable production costs of $0.02 perMWh (0.1 percent). For the remaining seven NERC regions, variable production costs increase by no more than $0.16 per MWh or 0.6 percent, with the maximum increase occurring in SERC.

Another potential market level impact of the proposed ELGs is the possible increase in electricity prices. While electricity prices increased in all NERC regions, the magnitude of that increase is small, ranging from \$0.06 per MWh (0.1 percent) in WECC to \$0.14 per MWh (0.3 percent) in SERC.

Finally, the impact on emissions is also small. At the national level, CO_2, Hg, and SO_2 emissions decline by 0.1 percent, while NOx and HCL emissions increase by 0.1 percent and 0.3 percent, respectively. While the impact on emissions varies by NERC region, increasing in some and declining in others, overall changes are small relative to the baseline.[82]

Findings for Regulatory Option 4

Overall, although national and regional market impacts of Option 4 in 2020 are greater compared to those of Option 3, they remain small.

At the national level, total production costs increase by 1.1 percent; this increase is mainly driven by increases in variable O&M costs (5.6 percent) and fixed O&M costs (1.9 percent). However, while capital costs also decline (0.1 percent), fuel costs increase slightly (0.1 percent). The impact of Option 4 on production-cost components varies across NERC regions and by cost component, with some cost components increasing in some and declining in other regions.

At the national level, variable production costs increase by 0.9 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 and varies across NERC regions, ranging from \$0.24 per MWh (0.5 percent) in WECC to \$0.45 per MWh (0.9 percent) in RFC.

The effects of Option 4 on air emissions are also small. At the national level, CO_2, Hg, and SO_2 emissions decline by 0.1 percent, 0.2 percent, and 0.03 percent, respectively, while NOx and HCL emissions increase by 0.1 and 0.4 percent. Emissions changes vary across NERC regions, increasing in some and declining in others, but are generally small.

5.4 Uncertainties and Limitations

EPA‟s analyses of the electric power market and the economic impacts of the proposed ELGs involve several sources of uncertainties:

- *Demand for electricity*: IPM assumes that electricity demand at the national level would 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 Version 4.10 embeds a baseline energy demand forecast that is derived from the Department of Energy‟s *Annual Energy Outlook 2010* (AEO 2010). IPM does not capture changes in demand that may result from electricity price increases associated with the proposed ELGs (i.e., demand is inelastic with respect to price). While this constraint may overestimate total demand in policy options that have high compliance cost and, therefore, potentially significant price increases, EPA believes that it does not affect the results analyzed in support of the proposed 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.

[82] 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).

- *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 AEO 2010‟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 plants, irrespective of the proposed ELGs.
- *International imports*: IPM assumes that imports from Canada and Mexico would not change between the baseline and the analyzed policy options. Holding international imports fixed would potentially overstate production costs and electricity prices, 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 believe that this assumption materially affects results, however, since only one of the eight NERC regions are projected to import electricity (WECC) in 2030, and the level of imports compared to domestic generation is very small (0.1 percent).
- *Compliance costs*: In the aggregate, compliance costs are 3 percent lower and 1 percent lower for Market Model Analysis Option 3 and Option 4, respectively, as compared to Option 3 and Option 4 discussed in other chapters of this document and in the BCA.

6 Assessing the Impact of the Proposed ELGs on Employment

While estimates of employment impacts are not typically included in a standard benefit-cost analysis,[83] such an analysis is of particular concern in the current economic climate of high unemployment, relative to long-term average levels. Executive Order 13563, which supplements Executive Order 12866, states, “Our regulatory system must protect public health, welfare, safety, and our environment while promoting economic growth, innovation, competitiveness, and job creation” (emphasis added). For the proposed ELGs, EPA conducted an assessment of the *potential* for employment impacts at the national level. EPA analyzed the employment effects of the eight options considered for the proposed ELGs for existing sources.

To assess the potential for a change in the number of jobs due to the proposed ELGs, the Agency estimated national level employment changes in the directly regulated electric power industry sector. Specifically, this employment effects analysis is based on an econometric analysis of industry response to environmental regulations and focuses on the *on-going* employment effects of meeting compliance requirements.[84]

The results of this analysis address requirements of the Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review, discussed in *Chapter 10: Other Administrative Requirements*.

6.1 Assessing Regulatory Employment Effects

Estimating employment effects of an environmental regulation is not a straightforward process as it requires consideration of many factors, some of which are difficult to isolate and quantify. Some difficulties arise due to lack of data, while others exist because of ambiguity of certain impacts to be captured. This section provides a general discussion of how an environmental regulation may potentially affect employment levels and a general assessment of the current employment levels in the electric power industry.

6.1.1 General Considerations

An environmental regulation can be understood as an increase in demand for a particular output: environmental quality. Meeting this new demand can lead to higher demand for various factors of production available to the economy (including labor) in the directly regulated sector(s) as well as in the environmental protection economic sectors comprised of industries providing goods and services to the directly regulated sector(s). However, polluting sectors generally have to rely on revenue generated by their other (market) outputs to cover the costs of satisfying society's demand for environmental quality. This can lead to reduced demand for labor and other factors of production in the directly regulated sector(s). The net effect of an environmental regulation on regulated sectors and the overall economy is therefore indeterminate. The costs imposed on directly regulated sectors may affect their competitive position and put some jobs at risk. At the same time, environmental regulations may create jobs in other sectors, e.g., in the environmental protection sector. Tracing out these opposing effects against the temporal dynamics of labor markets is complex and makes deriving estimates of how regulations will impact economy-wide net employment a difficult task.

83 One exception is the extent to which labor costs are part of total costs in a benefit cost analysis.

84 Note that this analysis accounts only for a subset of potential changes in employment; however, these are the employment impacts EPA can defensibly assess at this time. EPA is committed to using the best available science, utilizing the relevant theoretical and empirical literature in this assessment, and is pursuing efforts to support new research in this field.

Adding to this complexity, employment effects are also likely to change over time. Some employment effects occur soon after a regulation becomes effective, while other effects occur farther in the future, depending on the phasing of regulatory requirements and when the „steady state" compliance period is reached. Longer term, changes in employment will depend on how directly affected industries adjust to the new regulatory requirements, and the indirect upstream and downstream effects of those adjustments. For instance, in the long run, complying plants may be able to change their production processes in terms of the mix of production inputs, potentially leading to changes in demand for employment in the directly affected sector(s), and changes in demand for pollution control equipment and services provided by the environmental protection sector industries. Also, in the long run, directly affected sectors may be able to train their employees to perform certain services, for which they initially hired specialists from the environmental protection sector industries, thereby leading to reduced demand for services provided by the environmental protection sector industries. In addition, due to technological changes over time in compliance equipment and processes, a wider range of pollution control alternatives may become available, potentially changing the profile of demand for equipment and services, including employment.

In addition to varying over time, these direct and indirect impacts on employment levels can vary in their magnitude across regions, depending on regional variations in the operating characteristics of affected sectors. Regional differences in regulatory response are likely to result in offsetting direct and indirect effects, which vary across regions due to different regional presence of directly and indirectly affected industry sectors. In addition, the degree to which regulated entities will be able to increase prices to recover increased production costs may vary by region, depending on industry structure. Further, interconnectedness of industry sectors across regions is likely to result in spillover effects, which are generally difficult to capture. Estimates of partial or localized employment effects can paint an inaccurate picture of net employment impacts if not properly placed in a broader economic context. At the same time, differences in regulatory response, regional industry presence, industry structure, and potential spillover effects make estimating employment effects not only at the regional but also at the national level challenging.

It is important to account for the state of the economy at the time of regulatory action. When the economy is at full employment, an environmental regulation is unlikely to have a considerable impact on net employment in the long run; instead, labor would primarily be reallocated from one productive use to another, e.g. from producing electricity or steel to producing pollution abatement equipment. Even in the full employment case, however, transitory employment effects are possible, as some workers may require time to either retrain or look for new jobs. Regardless, overall, theory and peer-reviewed published empirical evidence support the argument that, in the case of full employment, the net employment effects from environmental regulation are likely to be small, even in the regulated sector. On the other hand, Schmalansee and Stavins point out that positive net employment effects are possible in the near term, during a period of sustained unemployment, due to the potential hiring of previously unemployed workers 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 (Schmalensee and Stavins, 2011). However, it is also theoretically possible to have near term negative net employment effects. For example, during periods of sustained high unemployment, workers displaced by regulations may require longer to find alternative employment. In the longer term, the net effect on employment is more difficult to estimate and will depend on the way in which the related industries respond to regulatory requirements and whether the labor market remains in sustained disequilibrium or returns to full employment. There are also significant methodological challenges in assessing the net employment impacts when the economy is not at full employment. For example, the opportunity cost of labor is more difficult to assess, labor demand caused by an environmental regulation may have positive external effects, and reductions in labor may give rise to negative external effects.

On top of these more general considerations, determining the direction of employment effects in the electric power industry is challenging due to industry-specific factors. As discussed in *Chapter 2: Industry Profile*, the he majority of steam electric plants (62 percent) operate in states with regulated electricity markets;. these plants, 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, may be able to pass these costs forward to customers in electricity rates. Consumers may respond to increased prices by reducing electricity purchases, but their ability to adjust demand is likely to be small given that electricity is required to operate a wide range of durable goods and equipment – for both household and commercial/industrial use. Thus, these plants may see little negative effect on production levels and/or employment. At the same time, plants operating in states where electric power generation has been deregulated are less likely to pass forward regulation-induced increases in their production costs via price increases, and, in an effort to remain competitive, may seek to reduce their production costs in other ways, one of which may be employment reductions.

Finally, because of the regional character of electricity markets, notably the differences in the generation profile (e.g., fuel mix) and the limited ability to sell electricity across regional boundaries, the regulation‟s employment effects can vary substantially across regions.

6.1.2 Employment in the Electric Power Industry

According to the U.S. Bureau of Labor Statistics (BLS), in 2011, the electric power generation, transmission and distribution sector (NAICS 2211) employed 398,000 people (BLS, 2012a). In the overall electric power sector, installation, maintenance, and repair occupations accounted for the largest share of workers (30 percent).[85] These occupation categories include jobs involved in inspection, testing, repairing and maintaining of electrical equipment and/or installation and repair of cables used in electrical power and distribution systems. Other major occupation categories include office and administrative support (17 percent), production occupations (15 percent), architecture and engineering (11 percent), business and financial operations (7 percent) and management (6 percent). The other occupation categories each account for less than 5 percent of employment in the industry (BLS, 2012b).

As shown in *Table 6-1*, employment in the electric power industry as a whole has declined relatively steadily since 1990 at an average annual rate of approximately 2 percent, resulting in an overall decrease of 28 percent. During the same time, electricity generation increased by 36 percent, leading to an overall decline in labor intensity (number of employees per TWh) of 47 percent. Therefore, while employment in this industry has likely been affected by changes in general economic conditions, technological changes have also been an important contributor, leading to higher factor productivity overall and a reduced need for labor in the electric power industry.

Table 6-1: Total Employment and Labor Intensity in the Electric Power Industry

Year	Number of Employees[a]	Electricity Generation[b]	Labor Intensity

[85] BLS does not provide specific occupational employment estimates for the electric power generation industry.

	Number of Employees	% Change	Generation (TWh)	% Change	Labor Intensity (Number of Employees per TWh)	% Change
1990	550,200	na	3,038	na	181	na
1991	544,300	-1.1%	3,074	1.2%	177	-2.2%
1992	536,700	-1.4%	3,084	0.3%	174	-1.7%
1993	523,100	-2.5%	3,197	3.7%	164	-6.0%
1994	504,400	-3.6%	3,248	1.6%	155	-5.1%
1995	486,000	-3.6%	3,353	3.3%	145	-6.7%
1996	464,200	-4.5%	3,444	2.7%	135	-7.0%
1997	449,200	-3.2%	3,492	1.4%	129	-4.6%
1998	443,800	-1.2%	3,620	3.7%	123	-4.7%
1999	438,400	-1.2%	3,695	2.1%	119	-3.2%
2000	434,400	-0.9%	3,802	2.9%	114	-3.7%
2001	433,800	-0.1%	3,737	-1.7%	116	1.6%
2002	433,800	0.0%	3,858	3.3%	112	-3.2%
2003	417,900	-3.7%	3,883	0.6%	108	-4.3%
2004	408,600	-2.2%	3,971	2.2%	103	-4.4%
2005	401,300	-1.8%	4,055	2.1%	99	-3.8%
2006	396,100	-1.3%	4,065	0.2%	97	-1.5%
2007	397,600	0.4%	4,157	2.3%	96	-1.8%
2008	403,700	1.5%	4,119	-0.9%	98	2.5%
2009	404,100	0.1%	3,950	-4.1%	102	4.4%
2010	398,000	-1.5%	4,125	4.4%	96	-5.7%
Total Percent Change (1990-2010)		**-27.7%**		**35.8%**		**-46.7%**
Total Percent Change (2000-2010)		**-8.4%**		**8.5%**		**-15.6%**
Average Annual Growth Rate (1990-2010)		**-1.6%**		**1.5%**		**-3.1%**

a. Total number of employees reported for NAICS 2211: Electric Power Generation, Transmission and Distribution. Includes full and part time, temporary and intermittent employees. Employee counts are not seasonally adjusted.

b. Net electricity generation reported in the 2010 Electric Power Annual report published by the Energy Information Administration.

Sources: U.S. DOE, 2001; U.S. DOE, 2011b; BLS, 2012a

6.2 Ongoing Employment Effects in the Electric Power Industry Sector

This analysis assesses the ongoing employment impacts estimated to occur in the electric power industry as it adjusts to regulatory requirements. The analysis accounts for all compliance costs, regardless of their time, frequency, and duration of incurrence. These effects result from meeting compliance requirements on an ongoing basis, with potential increases in the cost of electricity generation. In the long run, the confluence of various possible adjustment mechanisms may lead to an overall increase or decrease in employment in the directly affected electric power sector; as discussed in *Section 6.1.1*, adjustments in economy-wide employment would depend upon how the electric power sector adjusts to the new regulatory requirements.

The ambiguity in the direction of the long-term change in employment in the electric power sector, is amplified at the national economy-wide level when possible indirect impacts on employment in the environmental protection sector are taken into account. While regulation-induced demand for certain goods and services from the environmental protection sector may represent revenue and employment gains for the environmental protection sector, they are costs to the regulated electric power sector, thereby making it unclear whether the regulation would result in an overall positive or negative change in employment. Further, it is unclear whether a positive change in the number of people employed represents anything other than workers being diverted from other productive employment as opposed to new additional net employment.

Other potential effects on the overall economic activity and employment beyond the electric power sector are also uncertain. For example, potential regulation-induced increases in electricity prices can affect household expenditure profiles and the cost of producing goods and services in industries that consume electricity. Changes in output prices in these downstream linked industries can lead to further changes in production quantities and employment in those industries, and so on. Conversely, productivity improvements may result from reductions in the adverse health effects of pollutant discharges (see the *Benefit and Cost Analysis for Proposed Steam Electric Effluent Limitations Guidelines Regulation* (*BCA*) report for details; U.S. EPA, 2013b; DCN SE03172). All of these effects yield a range of employment effects in sectors that are linked directly or indirectly to the electric power industry. As the economy changes over time, these relationships are likely to change, perhaps substantially, due both to general technological change and to changes in response to the regulation, itself.

Because of the complexity of these interrelated factors and the myriad uncertainties in assessing economy-wide, long-term employment effects of a regulation, and the lack of a robust methodology to account for these factors, EPA focused the longer term employment effects analysis on employment changes occurring only in the electric power industry. Further, given the different character of potential employment effects associated with ongoing compliance (as compared to the relatively more straightforward effects associated with producing and installing compliance equipment), EPA based its methodology on an econometric analysis of industry response to environmental regulations. This analysis accounts for multiple response effects occurring only *within* the electric power industry (see below), and can lead to projected increases or decreases in employment due to regulatory requirements.

6.2.1 Analysis Approach and Data Inputs

EPA examined possible ongoing employment effects within the electric power sector using a peer-reviewed study conducted by Morgenstern, Pizer, and Shih. This study explores historical relationships between industrial employment and environmental regulations (Morgenstern, et al., 2002). EPA has recently used this study as the basis for estimating employment effects of new regulations affecting the electric power industry.[86]

In their attempts to capture competing forces affecting employment in the regulated industry in the long term, Morgenstern et al. demonstrated that environmental regulations could be understood as requiring regulated firms to add a new output (environmental quality) to their product mixes (Morgenstern, et al., 2002). Although legally compelled to satisfy this new demand, regulated firms have to finance this additional production with the proceeds of sales of their other (market) products. Satisfying this new demand requires additional inputs, including labor, and may alter the relative proportions of labor and capital used by regulated

[86] For example, EPA used the study to assess the employment effects on the electric power industry of the Final Mercury and Air Toxics Standards (MATS) and Cross-State Air Pollution Rule (CSAPR).

firms in their production processes. Consequently, Morgenstern et al. decomposed the direct effect of regulation on net employment in the regulated sector into three subcomponents:

- *The Demand Effect*: higher production costs from complying with the regulation will raise market prices, reducing consumption (and production), thereby reducing demand for labor within the regulated industry. The "extent of this effect depends on the cost increase passed on to consumers as well as the demand elasticity of industry output." (Morgenstern, et al., 2002; p. 416)
- *The Cost Effect*: Assuming that the capital/labor ratio in the production process is held fixed, as "production costs rise, more inputs, including labor, are used to produce the same amount of output," (Morgenstern, et al., 2002; p. 416). For example, to reduce pollutant emissions while holding output levels constant, regulated firms may require additional labor.
- *The Factor-Shift Effect*: Regulated firms" production technologies may be more or less labor intensive after complying with the regulation (i.e., more/less labor is required relative to capital per dollar of output). "Environmental activities may be more labor intensive than conventional production," meaning that "the amount of labor per dollar of output will rise." However, activities may, instead, be less labor intensive because "cleaner operations could involve automation and less employment, for example." (Morgenstern, et al., 2002; p. 416)

In their study, Morgenstern et al. used plant-level U.S Census Bureau data for 1979 through 1991 to estimate the size of each of the three direct employment effect subcomponents, as well as the net effect, for four highly polluting/regulated industries: pulp and paper, plastics, petroleum, and steel. For each of these industries, the study estimated a change in the number of jobs per $1 million (in 1987 dollars) of additional expenditures due to compliance with an environmental regulation.

According to the Morgenstern et al. study results for the four analyzed industry sectors, the *demand effect* is expected to have an unambiguously negative effect on employment, the *cost effect* to have an unambiguously positive effect on employment, and the *factor-shift effect* to have an ambiguous effect on employment. Therefore, without more information with respect to the magnitudes of these competing effects, it is not possible to predict the total effect that an environmental regulation will have on overall employment levels in the regulated sector. Overall, however, the Morgenstern et al. results suggest that increased pollution abatement expenditures generally do not cause a significant change in net employment. More specifically, their results indicate that, on average across the industries studied by Morgenstern et al., each additional $1 million spending on pollution abatement results in a (statistically insignificant) net increase of 1.55 jobs (at the 95 percent confidence interval, results range from approximately -2.84 to + 5.94 (i.e., 1.55 ± 4.39).[87]

The four industries analyzed by Morgenstern et al. do not include the electric power industry. The analyzed industries may differ from the electric power industry sector in terms of the effects of environmental compliance expenditures on employment. Specifically, the control technologies described for this rule likely differ from those in the four industries analyzed by Morgenstern et al.,but it is not possible to assess the magnitude or direction of these differences on employment effects. Consequently, EPA estimated the change in the number of jobs in the electric power industry sector due to the proposed ELGs using, the *average total* effect coefficient of 1.55 jobs per $1 million ($1987) in spending. Specifically, the Agency multiplied

[87] These results are similar to Berman and Bui, who find that while air quality regulation in Los Angeles to reduce NOx emissions resulted in large abatement costs, they did not result in substantially reduced employment. "Environmental regulation and labor demand: evidence from the South Coast Air Basin." *Journal of Public Economics* 79(2): 265-295.

average annual compliance cost values estimated as part of the social cost analysis (see *BCA Chapter 11: Assessment of Total Social Costs*), re-stated in 1987 dollars using the Gross Domestic Product (GDP) deflator index published by the U.S. Bureau of Economic Analysis (BEA), by 1.55. EPA also calculated the range in effects based on employment changes estimated at the 95 percent confidence level.

6.2.2 Key Findings for Regulatory Options

While the specific sectors Morgenstern et al. examined differ from the electric power sector, EPA believes that the Morgenstern et al. methodology provides useful insight on the potential employment effects of the proposed ELGs. *Table 6-2* presents the estimated average annual change in employment in the electric power industry due to the proposed ELGs.

The estimated average annual increase in the number of jobs under Option 3a is 168 jobs, with a 95 percent confidence interval ranging from a decrease of 308 jobs to an increase of 644 jobs. Options 3b and 3 are estimated to result in an average annual increase of 255 jobs (ranging from a decrease of 468 to an increase of 978 jobs) and 519 jobs (ranging from a decrease of 951 to and increase of 1,989 jobs), respectively, whereas Option 4a is estimated to result in an average annual increase of 865 jobs, with a 95 percent confidence interval ranging from a decrease of 1,586 jobs to an increase of 3,317 jobs.

Table 6-2: Ongoing Employment Effects on the Electric Power Industry Sector (Average Annual Change in the Number of Jobs)

Regulatory Option	Employment Effect	Total Annual Average Employment Effect (Number of Jobs)	95% Confidence Interval on Total Effect (Number of Jobs)	
			Lower Bound	Upper Bound
Option 3a	Cost	262	86	439
	Factor Shift	291	4	577
	Demand	-386	-817	45
	Total	**168**	**-308**	**644**
Option 3b	Cost	399	131	667
	Factor Shift	441	6	877
	Demand	-586	-1,242	69
	Total	**255**	**-468**	**978**
Option 1	Cost	380	125	636
	Factor Shift	421	5	836
	Demand	-559	-1,184	66
	Total	**243**	**-446**	**933**
Option 2	Cost	548	180	916
	Factor Shift	607	8	1,206
	Demand	-806	-1,707	95
	Total	**351**	**-643**	**1,345**
Option 3	Cost	810	266	1,355
	Factor Shift	897	11	1,783
	Demand	-1,192	-2,524	140
	Total	**519**	**-951**	**1,989**
Option 4a	Cost	1,351	443	2,260
	Factor Shift	1,496	19	2,974
	Demand	-1,988	-4,209	234

Table 6-2: Ongoing Employment Effects on the Electric Power Industry Sector (Average Annual Change in the Number of Jobs)

Regulatory Option	Employment Effect	Total Annual Average Employment Effect (Number of Jobs)	95% Confidence Interval on Total Effect (Number of Jobs)	
			Lower Bound	Upper Bound
	Total	**865**	**-1,586**	**3,317**
Option 4	Cost	1,956	641	3,271
	Factor Shift	2,166	27	4,305
	Demand	-2,878	-6,094	339
	Total	**1,253**	**-2,296**	**4,802**
Option 5	Cost	3,298	1,081	5,515
	Factor Shift	3,653	46	7,259
	Demand	-4,852	-10,274	571
	Total	**2,112**	**-3,871**	**8,096**

Source: U.S. EPA Analysis, 2013

As noted above, the demand and factor-shift effects accounted for in this analysis reflect experience in industries that are quite different from the electric power industry. Accordingly, employment effects in the electric power industry may be different from those estimated for these industries.

Changes in the electric power industry, as it adapts to the new regulatory requirements, and consequent upstream (e.g., sectors supporting electric power industry) and downstream (e.g., electricity consumers) responses would determine the on-going economy-wide changes in employment. For example, in their attempt to offset increased production costs, steam electric power plants may switch away from coal to a different fuel with fewer requirements under the proposed ELGs. This change would result in lower domestic demand for coal, potentially leading to decreased labor demand in the coal mining sector and supporting sectors. At the same time, the demand for an alternative fuel source, such as natural gas, may increase, leading to higher labor demand in the oil and gas extraction sector and supporting sectors. These effects due to input substitution are difficult to estimate, particularly without specific information from those industries.

Even if steam electric plants are able to reduce their electricity generation costs by changing their production processes, in the post-rule environment, electricity generation costs may still be higher compared to those before the rule promulgation. Attempts by steam electric plants to recover increases in production costs, however small, are likely to result in higher electricity rates. The impact of this increase, however small, would vary by region, customer classes (e.g., industrial, commercial, transportation, and residential), and industry sectors depending on the intensity of their electricity use (see *Chapter 5: Electricity Market Analyses* for assessment of the impacts of increased production costs on wholesale electricity prices and *Chapter 4: Economic Impact Screening Analyses* for screening-level analyses of the impacts of increased production costs on retail rates by customer classes). Further, the extent to which steam electric plants are able to pass their costs to consumers through higher electricity rates, would vary by region. Specifically, plants operating in regions where electricity prices remain regulated under the traditional cost-of-service rate regulation framework, depending on a business operation model of the plant ownership structure, a plant ownership structure itself, as well as the importance and role of market mechanisms used to sell electricity, may be able to recover compliance cost-based increases in increased rates. However, cost recovery is more uncertain for plants operating in states where electric power generation has been deregulated, and would depend on the competitive circumstances of specifically affected plants. Because of these and many other interrelated factors not mentioned here, it is difficult to fully assess the upstream and downstream impact of the proposed ELGs and consequent economy-wide change in employment.

6.2.3 Uncertainties and Limitations

Key uncertainties and limitations to consider for this analysis include:

- This analysis estimates ongoing annual average employment impacts for the electric power sector and does not include employment effects in the environmental protection economic sector – i.e., the sector comprised of industries supporting the design, construction, and implementation of control technologies.
- This analysis uses coefficient estimates developed by Morgenstern et al. (2002) for industries other than the regulated electric power industry. Consequently, these coefficient estimates do not reflect the potential response of the electric power industry to changes in production costs and/or input factor composition specifically. Employment coefficients for each subcomponent range widely across the four industries analyzed by Morgenstern et al. To the extent that the electric power sector is less labor-intensive than the industries examined by Morgenstern et al. (2002), it is possible that the positive employment impacts estimated here are too high. Further, it is reasonable to assume that responses to regulatory requirements are industry-specific and that the employment effect coefficients might be quite different if they were estimated specifically for the electric power industry. Consequently, the calculated employment effects of the proposed ELGs may be over- or under-stated.
- The Morgenstern et al. (2002), employment impact estimates were developed using 1979-1991 data. Consequently, the estimated employment effect parameters may not reflect structural, operational, and/or technological changes in the four analyzed industries that might have affected industry response to changes in production costs and/or input factor composition more recently.
- Finally, the methodology used in Morgenstern et al. assumes that regulations affect plants in proportion to their total costs. In other words, each additional dollar of regulatory burden affects a plant by an amount equal to that plant,s total costs relative to the aggregate industry costs. By transferring the estimates, EPA assumes a similar distribution of regulatory costs by plant size and that the regulatory burden does not disproportionately fall on smaller or larger plants.

6.3 Overall Analysis Conclusion

As discussed in *Section 6.1* and throughout this chapter, because of the complexity of numerous interrelated factors, myriad uncertainties, and data constraints, it is difficult to project how the proposed ELGs would affect employment levels, not only in the directly regulated electric power industry but in the entire U.S. economy. EPA does not currently have a robust methodology to fully assess the impact of all possible changes in employment. The analysis of long-term changes in employment levels in the regulated electric power industry presented here addresses only one aspect of potential employment effects. For example, employment impacts due to increased demand for pollution control equipment were not included.

Employment effects are likely to vary in their magnitude over time and across sectors. Environmental regulations are typically phased in to allow firms time to invest in the necessary technology and process changes to meet the new standards. Noticeable effects of a regulation on employment in the regulated sector would typically not occur until after a regulation takes effect. When a regulation is promulgated, the first response of industry is to order pollution control equipment. As the compliance date of the regulation approaches, the installation of needed pollution control equipment can produce a short-term increase in labor demand for specialized workers within the environmental protection sector, which may or may not include a directly regulated industry sector (Schmalansee and Stavins, 2011). These short-term employment effects essentially occur once as affected plants move to comply with the regulation, and are expected to occur to a substantial degree in the industries that produce and install compliance equipment, and are thus largely external to the directly regulated industries. In the short run, spanning the initial technology implementation window of 2017 through 2021, the proposed ELGs are likely to affect the regulated electric power sector, fabricated metal products manufacturing sector, construction sector, and professional, scientific, and technical services sector, i.e., sectors comprising the environmental protection economic sector, based on the type of compliance equipment and services identified in the *Technical Development Document* (*TDD*) (U.S. EPA, 2013a; DCN SE01964). In aggregate, these four sectors are likely to experience a temporary increase in jobs created as more pollution control systems are designed, manufactured, and installed due to the proposed ELGs. In addition, because of regional variation in the presence of steam electric plants and supporting industries, and in consumption patterns, it is likely that short- and long-run employment effects with vary across the United States. According to BLS, the current economy-wide unemployment rate (e.g., as of April 2013) is still high, relative to the long-term averages, at 7.5 percent (BLS, 2013). Therefore, it is possible that the potential hiring of idle labor resources by the regulated electric power sector to plan for and meet new pollution control requirements would result in positive net employment effects in the near term, as opposed to workers diverted from other productive employment.

The long-run *economy-wide* regulatory changes in employment, which EPA did not quantify, would depend on how the electric power sector adjusts in response to the new regulatory requirements, the indirect upstream and downstream effects of those adjustments on the rest of the economy, as well as the overall state of the economy and labor markets. It is possible that in the long run, as the economy returns to full employment, any changes in employment in the electric power sector due to the proposed ELGs would be mostly offset by employment changes in other sectors.

In the long run, employment effects in the directly affected *electric power sector* would depend on a number of economic factors, including changes in labor requirements to operate the electric industry‟s infrastructure in general and compliance technology in particular, the potential to switch fuel sources, potential changes in fuel prices, changes in productivity, availability of alternative technologies to meet compliance requirements, and changes in demand for electricity.

7 Assessment of Potential Electricity Price Effects

7.1 Analysis Overview

As part of its assessment of the cost and economic impact of the proposed ELG regulatory options 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 plants in response to regulatory requirements. However, unlike the plant- and entity-level screening analyses which assume that steam electric 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). *If this full cost pass-through condition were to occur, the screening analyses assessed in Chapter 4 would not be relevant because the two conditions (no cost pass-through and full cost pass-through) could not simultaneously occur for the same steam electric plant.*

As discussed in *Chapter 2: Industry Profile*, 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 complying 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.

For the purpose of the electricity price impact assessment discussed in this Chapter, the Agency assumed that 100 percent of compliance costs would be passed through to consumers. Although this convenient analytical simplification does not reflect actual market conditions, EPA judges that this assumption is appropriate for two reasons: (1) the majority of steam electric 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.[88]

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.[89,90] The steps in this calculation are as follows:

- EPA summed weighted pre-tax plant-level annualized compliance costs in 2014 by NERC region.[91, 92]
- 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 2014 by NERC region, from *AEO2010*.[93] EPA followed this approach for all NERC regions except Alaska System Coordinating Council (ASCC) and Hawaii Coordinating Council (HICC), for which the Agency used the historical quantity of electricity sales – total and by consumer group – from the 2009 EIA-861 database.
- EPA compared the estimated average price effect to the projected electricity price by consumer group and NERC region for 2014 from *AEO2010* 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 2009 EIA-861 database.

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88 To evaluate the sensitivity of the results to the cost pass-through assumption, EPA also analyzed Option 3 based on the assumption that steam electric plants will be able to pass through 50 percent of their compliance costs to consumers through higher electricity prices (Fifty-Percent Cost-Pass-Through). The results of this sensitivity analysis are reported in *Appendix B*.

89 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 proposed ELG analyses vary by analysis depending on which region definition aligns better with the data elements underlying the analysis.

90 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*).

91 These compliance costs are in 2010 dollars as of a given technology implementation year (2017 through 2021) and discounted to 2014 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 (2017 through 2021) and then discounting these effects to a single analysis year (2014) accounts for this consideration.

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

93 EPA used *AEO2010* as opposed to more current AEO data available at the time of this analysis because the NERC-region definition used in the *AEO2010* publication aligned better with the NERC-region definition in the EIA-861 database also used for this analysis.

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 ECAR region for all eight options analyzed, followed by the SERC region. On average, across the United States, Option 3a results in the lowest cost of 0.004¢ per KWh, while Option 5 results in the highest cost of 0.059¢ per KWh. The preferred options result in national costs of 0.004¢, 0.007¢, 0.015¢ and 0.025¢ per KWh, respectively for Options 3a, 3b, 3 and 4a.

Table 7-1: Compliance Cost per KWh of Sales by NERC Region and Regulatory Option in 2014 ($2010) [a]

NERC Region	Annualized Pre-Tax Compliance Costs (at 2014; $2010)	Total Electricity Sales (at 2014; KWh)	Costs per Unit of Sales (2010¢/KWh Sales)
Option 3a			
ASCC	$0	6,427,040,000	0.000
ECAR	$89,589,899	562,390,686,000	0.016
ERCOT	$0	300,895,599,000	0.000
FRCC	$0	226,942,169,000	0.000
HICC	$0	10,125,934,000	0.000
MAAC	$0	287,861,511,000	0.000
MAIN	$9,520,495	275,205,261,000	0.003
MAPP	$226,272	162,173,447,000	0.000
NPCC	$0	286,114,145,000	0.000
SERC	$64,289,350	836,496,826,000	0.008
SPP	$792,306	197,315,811,000	0.000
WECC	$3,660,919	679,947,516,000	0.001
U.S.	**$168,079,242**	**3,831,895,945,000**	**0.004**
Option 3b			
ASCC	$0	6,427,040,000	0.000
ECAR	$121,509,392	562,390,686,000	0.022
ERCOT	$9,073,578	300,895,599,000	0.003
FRCC	$0	226,942,169,000	0.000
HICC	$0	10,125,934,000	0.000
MAAC	$0	287,861,511,000	0.000
MAIN	$9,520,495	275,205,261,000	0.003
MAPP	$226,272	162,173,447,000	0.000
NPCC	$0	286,114,145,000	0.000
SERC	$118,319,085	836,496,826,000	0.014
SPP	$2,283,936	197,315,811,000	0.001
WECC	$3,660,919	679,947,516,000	0.001
U.S.	**$264,593,677**	**3,831,895,945,000**	**0.007**
Option 1			
ASCC	$0	6,427,040,000	0.000
ECAR	$96,782,075	562,390,686,000	0.017
ERCOT	$26,339,280	300,895,599,000	0.009
FRCC	$2,970,728	226,942,169,000	0.001
HICC	$0	10,125,934,000	0.000
MAAC	$1,743,343	287,861,511,000	0.001
MAIN	$14,512,921	275,205,261,000	0.005
MAPP	$15,007,890	162,173,447,000	0.009
NPCC	$1,252,830	286,114,145,000	0.000
SERC	$96,452,227	836,496,826,000	0.012
SPP	$9,628,222	197,315,811,000	0.005
WECC	$1,200,969	679,947,516,000	0.000

Table 7-1: Compliance Cost per KWh of Sales by NERC Region and Regulatory Option in 2014 ($2010) [a]

NERC Region	Annualized Pre-Tax Compliance Costs (at 2014; $2010)	Total Electricity Sales (at 2014; KWh)	Costs per Unit of Sales (2010¢/KWh Sales)
U.S.	**$265,890,484**	**3,831,895,945,000**	**0.007**
Option 2			
ASCC	$0	6,427,040,000	0.000
ECAR	$143,970,919	562,390,686,000	0.026
ERCOT	$37,299,017	300,895,599,000	0.012
FRCC	$11,182,413	226,942,169,000	0.005
HICC	$0	10,125,934,000	0.000
MAAC	$9,494,272	287,861,511,000	0.003
MAIN	$21,022,444	275,205,261,000	0.008
MAPP	$20,112,267	162,173,447,000	0.012
NPCC	$2,961,927	286,114,145,000	0.001
SERC	$129,799,304	836,496,826,000	0.016
SPP	$15,230,666	197,315,811,000	0.008
WECC	$2,195,920	679,947,516,000	0.000
U.S.	**$393,269,150**	**3,831,895,945,000**	**0.010**
Option 3			
ASCC	$0	6,427,040,000	0.000
ECAR	$233,560,818	562,390,686,000	0.042
ERCOT	$37,299,017	300,895,599,000	0.012
FRCC	$11,182,413	226,942,169,000	0.005
HICC	$0	10,125,934,000	0.000
MAAC	$9,494,272	287,861,511,000	0.003
MAIN	$30,542,939	275,205,261,000	0.011
MAPP	$20,338,539	162,173,447,000	0.013
NPCC	$2,961,927	286,114,145,000	0.001
SERC	$194,088,655	836,496,826,000	0.023
SPP	$16,022,972	197,315,811,000	0.008
WECC	$5,856,839	679,947,516,000	0.001
U.S.	**$561,348,392**	**3,831,895,945,000**	**0.015**
Option 4a			
ASCC	$0	6,427,040,000	0.000
ECAR	$382,925,214	562,390,686,000	0.068
ERCOT	$56,007,875	300,895,599,000	0.019
FRCC	$11,182,413	226,942,169,000	0.005
HICC	$0	10,125,934,000	0.000
MAAC	$28,546,920	287,861,511,000	0.010
MAIN	$77,380,834	275,205,261,000	0.028
MAPP	$31,521,541	162,173,447,000	0.019
NPCC	$2,966,374	286,114,145,000	0.001
SERC	$295,056,291	836,496,826,000	0.035
SPP	$45,223,870	197,315,811,000	0.023
WECC	$16,944,862	679,947,516,000	0.002
U.S.	**$947,756,195**	**3,831,895,945,000**	**0.025**
Option 4			
ASCC	$0	6,427,040,000	0.000
ECAR	$535,051,837	562,390,686,000	0.095
ERCOT	$60,192,862	300,895,599,000	0.020
FRCC	$16,638,136	226,942,169,000	0.007
HICC	$0	10,125,934,000	0.000
MAAC	$59,894,195	287,861,511,000	0.021

Table 7-1: Compliance Cost per KWh of Sales by NERC Region and Regulatory Option in 2014 ($2010) [a]

NERC Region	Annualized Pre-Tax Compliance Costs (at 2014; $2010)	Total Electricity Sales (at 2014; KWh)	Costs per Unit of Sales (2010¢/KWh Sales)
MAIN	$140,243,878	275,205,261,000	0.051
MAPP	$49,842,966	162,173,447,000	0.031
NPCC	$18,965,753	286,114,145,000	0.007
SERC	$382,915,981	836,496,826,000	0.046
SPP	$70,233,678	197,315,811,000	0.036
WECC	$39,270,065	679,947,516,000	0.006
U.S.	**$1,373,249,350**	**3,831,895,945,000**	**0.036**
Option 5			
ASCC	$0	6,427,040,000	0.000
ECAR	$894,852,326	562,390,686,000	0.159
ERCOT	$124,331,807	300,895,599,000	0.041
FRCC	$72,258,936	226,942,169,000	0.032
HICC	$0	10,125,934,000	0.000
MAAC	$103,253,011	287,861,511,000	0.036
MAIN	$186,704,789	275,205,261,000	0.068
MAPP	$86,137,684	162,173,447,000	0.053
NPCC	$26,280,950	286,114,145,000	0.009
SERC	$639,838,743	836,496,826,000	0.076
SPP	$99,911,219	197,315,811,000	0.051
WECC	$43,712,271	679,947,516,000	0.006
U.S.	**$2,277,281,737**	**3,831,895,945,000**	**0.059**

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

Source: U.S. EPA Analysis, 2013; U.S. DOE 2010b; U.S. DOE 2009c

To determine the relative significance of these compliance costs on electricity prices across consumer groups, EPA compared the per KWh compliance cost to baseline electricity prices by consuming group, and for the average of the groups. As reported in *Table 7-2*, across the United States, Option 3a is estimated to result in the smallest electricity price increase relative to baseline electricity prices, 0.05 percent, while Option 5 is estimated to yield the largest increase of 0.66 percent; the other three preferred options are estimated to result in increases of 0.08 percent, 0.16 percent, and 0.27 percent, respectively for Options 3b, 3 and 4a.

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 3, the estimated increase of 0.015 ¢/KWh represents 0.24 percent of the baseline electricity price for industrial consumers, and 0.13 percent of that for residential consumers, whereas for Option 4a, the 0.025 ¢/KWh represents 0.41 percent of the baseline electricity price for industrial consumers, and 0.23 percent of that for residential consumers.

Table 7-2: Projected 2014 Price (Cents per KWh of Sales) and Potential Price Increase Due to Compliance Costs by NERC Region and Regulatory Option ($2010) [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 3a											
ASCC	0.000	17.56	0.00%	17.56	0.00%	17.56	0.00%	17.56	0.00%	17.56	0.00%
ECAR	0.016	9.61	0.17%	8.42	0.19%	5.61	0.28%	7.79	0.20%	7.79	0.20%

Table 7-2: Projected 2014 Price (Cents per KWh of Sales) and Potential Price Increase Due to Compliance Costs by NERC Region and Regulatory Option ($2010)[a]

NERC Region	Compliance Cost (¢/KWh)	Residential Baseline Price	Residential % Change	Commercial Baseline Price	Commercial % Change	Industrial Baseline Price	Industrial % Change	Transportation Baseline Price	Transportation % Change	All Sector Average Baseline Price	All Sector Average % Change
ERCOT	0.000	12.04	0.00%	8.09	0.00%	6.34	0.00%	9.10	0.00%	9.15	0.00%
FRCC	0.000	12.89	0.00%	11.00	0.00%	8.66	0.00%	9.63	0.00%	11.81	0.00%
HICC	0.000	24.43	0.00%	24.43	0.00%	24.43	0.00%	24.43	0.00%	24.43	0.00%
MAAC	0.000	11.54	0.00%	9.33	0.00%	6.61	0.00%	9.39	0.00%	9.59	0.00%
MAIN	0.003	10.00	0.03%	8.25	0.04%	4.61	0.08%	7.74	0.04%	7.64	0.05%
MAPP	0.000	8.97	0.00%	7.09	0.00%	5.04	0.00%	6.32	0.00%	7.02	0.00%
NPCC	0.000	17.53	0.00%	13.15	0.00%	8.57	0.00%	14.33	0.00%	13.94	0.00%
SERC	0.008	9.12	0.08%	7.85	0.10%	5.69	0.13%	6.80	0.11%	7.74	0.10%
SPP	0.000	9.25	0.00%	7.91	0.01%	5.98	0.01%	6.21	0.01%	7.88	0.01%
WECC	0.001	11.32	0.00%	10.32	0.01%	7.20	0.01%	9.91	0.01%	9.95	0.01%
U.S.	**0.004**	**10.95**	**0.04%**	**9.23**	**0.05%**	**6.03**	**0.07%**	**10.10**	**0.04%**	**9.03**	**0.05%**
Option 3b											
ASCC	0.000	17.56	0.00%	17.56	0.00%	17.56	0.00%	17.56	0.00%	17.56	0.00%
ECAR	0.022	9.61	0.22%	8.42	0.26%	5.61	0.39%	7.79	0.28%	7.79	0.28%
ERCOT	0.003	12.04	0.03%	8.09	0.04%	6.34	0.05%	9.10	0.03%	9.15	0.03%
FRCC	0.000	12.89	0.00%	11.00	0.00%	8.66	0.00%	9.63	0.00%	11.81	0.00%
HICC	0.000	24.43	0.00%	24.43	0.00%	24.43	0.00%	24.43	0.00%	24.43	0.00%
MAAC	0.000	11.54	0.00%	9.33	0.00%	6.61	0.00%	9.39	0.00%	9.59	0.00%
MAIN	0.003	10.00	0.03%	8.25	0.04%	4.61	0.08%	7.74	0.04%	7.64	0.05%
MAPP	0.000	8.97	0.00%	7.09	0.00%	5.04	0.00%	6.32	0.00%	7.02	0.00%
NPCC	0.000	17.53	0.00%	13.15	0.00%	8.57	0.00%	14.33	0.00%	13.94	0.00%
SERC	0.014	9.12	0.16%	7.85	0.18%	5.69	0.25%	6.80	0.21%	7.74	0.18%
SPP	0.001	9.25	0.01%	7.91	0.01%	5.98	0.02%	6.21	0.02%	7.88	0.01%
WECC	0.001	11.32	0.00%	10.32	0.01%	7.20	0.01%	9.91	0.01%	9.95	0.01%
U.S.	**0.007**	**10.95**	**0.06%**	**9.23**	**0.07%**	**6.03**	**0.11%**	**10.10**	**0.07%**	**9.03**	**0.08%**
Option 1											
ASCC	0.000	17.56	0.00%	17.56	0.00%	17.56	0.00%	17.56	0.00%	17.56	0.00%
ECAR	0.017	9.61	0.18%	8.42	0.20%	5.61	0.31%	7.79	0.22%	7.79	0.22%
ERCOT	0.009	12.04	0.07%	8.09	0.11%	6.34	0.14%	9.10	0.10%	9.15	0.10%
FRCC	0.001	12.89	0.01%	11.00	0.01%	8.66	0.02%	9.63	0.01%	11.81	0.01%
HICC	0.000	24.43	0.00%	24.43	0.00%	24.43	0.00%	24.43	0.00%	24.43	0.00%
MAAC	0.001	11.54	0.01%	9.33	0.01%	6.61	0.01%	9.39	0.01%	9.59	0.01%
MAIN	0.005	10.00	0.05%	8.25	0.06%	4.61	0.11%	7.74	0.07%	7.64	0.07%
MAPP	0.009	8.97	0.10%	7.09	0.13%	5.04	0.18%	6.32	0.15%	7.02	0.13%
NPCC	0.000	17.53	0.00%	13.15	0.00%	8.57	0.01%	14.33	0.00%	13.94	0.00%
SERC	0.012	9.12	0.13%	7.85	0.15%	5.69	0.20%	6.80	0.17%	7.74	0.15%
SPP	0.005	9.25	0.05%	7.91	0.06%	5.98	0.08%	6.21	0.08%	7.88	0.06%
WECC	0.000	11.32	0.00%	10.32	0.00%	7.20	0.00%	9.91	0.00%	9.95	0.00%
U.S.	**0.007**	**10.95**	**0.06%**	**9.23**	**0.08%**	**6.03**	**0.12%**	**10.10**	**0.07%**	**9.03**	**0.08%**
Option 2											
ASCC	0.000	17.56	0.00%	17.56	0.00%	17.56	0.00%	17.56	0.00%	17.56	0.00%
ECAR	0.026	9.61	0.27%	8.42	0.30%	5.61	0.46%	7.79	0.33%	7.79	0.33%
ERCOT	0.012	12.04	0.10%	8.09	0.15%	6.34	0.20%	9.10	0.14%	9.15	0.14%
FRCC	0.005	12.89	0.04%	11.00	0.04%	8.66	0.06%	9.63	0.05%	11.81	0.04%
HICC	0.000	24.43	0.00%	24.43	0.00%	24.43	0.00%	24.43	0.00%	24.43	0.00%
MAAC	0.003	11.54	0.03%	9.33	0.04%	6.61	0.05%	9.39	0.04%	9.59	0.03%
MAIN	0.008	10.00	0.08%	8.25	0.09%	4.61	0.17%	7.74	0.10%	7.64	0.10%
MAPP	0.012	8.97	0.14%	7.09	0.17%	5.04	0.25%	6.32	0.20%	7.02	0.18%

Table 7-2: Projected 2014 Price (Cents per KWh of Sales) and Potential Price Increase Due to Compliance Costs by NERC Region and Regulatory Option ($2010)[a]

NERC Region	Compliance Cost (¢/KWh)	Residential Baseline Price	Residential % Change	Commercial Baseline Price	Commercial % Change	Industrial Baseline Price	Industrial % Change	Transportation Baseline Price	Transportation % Change	All Sector Average Baseline Price	All Sector Average % Change
NPCC	0.001	17.53	0.01%	13.15	0.01%	8.57	0.01%	14.33	0.01%	13.94	0.01%
SERC	0.016	9.12	0.17%	7.85	0.20%	5.69	0.27%	6.80	0.23%	7.74	0.20%
SPP	0.008	9.25	0.08%	7.91	0.10%	5.98	0.13%	6.21	0.12%	7.88	0.10%
WECC	0.000	11.32	0.00%	10.32	0.00%	7.20	0.00%	9.91	0.00%	9.95	0.00%
U.S.	**0.010**	**10.95**	**0.09%**	**9.23**	**0.11%**	**6.03**	**0.17%**	**10.10**	**0.10%**	**9.03**	**0.11%**
Option 3											
ASCC	0.000	17.56	0.00%	17.56	0.00%	17.56	0.00%	17.56	0.00%	17.56	0.00%
ECAR	0.042	9.61	0.43%	8.42	0.49%	5.61	0.74%	7.79	0.53%	7.79	0.53%
ERCOT	0.012	12.04	0.10%	8.09	0.15%	6.34	0.20%	9.10	0.14%	9.15	0.14%
FRCC	0.005	12.89	0.04%	11.00	0.04%	8.66	0.06%	9.63	0.05%	11.81	0.04%
HICC	0.000	24.43	0.00%	24.43	0.00%	24.43	0.00%	24.43	0.00%	24.43	0.00%
MAAC	0.003	11.54	0.03%	9.33	0.04%	6.61	0.05%	9.39	0.04%	9.59	0.03%
MAIN	0.011	10.00	0.11%	8.25	0.13%	4.61	0.24%	7.74	0.14%	7.64	0.15%
MAPP	0.013	8.97	0.14%	7.09	0.18%	5.04	0.25%	6.32	0.20%	7.02	0.18%
NPCC	0.001	17.53	0.01%	13.15	0.01%	8.57	0.01%	14.33	0.01%	13.94	0.01%
SERC	0.023	9.12	0.25%	7.85	0.30%	5.69	0.41%	6.80	0.34%	7.74	0.30%
SPP	0.008	9.25	0.09%	7.91	0.10%	5.98	0.14%	6.21	0.13%	7.88	0.10%
WECC	0.001	11.32	0.01%	10.32	0.01%	7.20	0.01%	9.91	0.01%	9.95	0.01%
U.S.	**0.015**	**10.95**	**0.13%**	**9.23**	**0.16%**	**6.03**	**0.24%**	**10.10**	**0.14%**	**9.03**	**0.16%**
Option 4a											
ASCC	0.000	17.56	0.00%	17.56	0.00%	17.56	0.00%	17.56	0.00%	17.56	0.00%
ECAR	0.068	9.61	0.71%	8.42	0.81%	5.61	1.21%	7.79	0.87%	7.79	0.87%
ERCOT	0.019	12.04	0.15%	8.09	0.23%	6.34	0.29%	9.10	0.20%	9.15	0.20%
FRCC	0.005	12.89	0.04%	11.00	0.04%	8.66	0.06%	9.63	0.05%	11.81	0.04%
HICC	0.000	24.43	0.00%	24.43	0.00%	24.43	0.00%	24.43	0.00%	24.43	0.00%
MAAC	0.010	11.54	0.09%	9.33	0.11%	6.61	0.15%	9.39	0.11%	9.59	0.10%
MAIN	0.028	10.00	0.28%	8.25	0.34%	4.61	0.61%	7.74	0.36%	7.64	0.37%
MAPP	0.019	8.97	0.22%	7.09	0.27%	5.04	0.39%	6.32	0.31%	7.02	0.28%
NPCC	0.001	17.53	0.01%	13.15	0.01%	8.57	0.01%	14.33	0.01%	13.94	0.01%
SERC	0.035	9.12	0.39%	7.85	0.45%	5.69	0.62%	6.80	0.52%	7.74	0.46%
SPP	0.023	9.25	0.25%	7.91	0.29%	5.98	0.38%	6.21	0.37%	7.88	0.29%
WECC	0.002	11.32	0.02%	10.32	0.02%	7.20	0.03%	9.91	0.03%	9.95	0.03%
U.S.	**0.025**	**10.95**	**0.23%**	**9.23**	**0.27%**	**6.03**	**0.41%**	**10.10**	**0.24%**	**9.03**	**0.27%**
Option 4											
ASCC	0.000	17.56	0.00%	17.56	0.00%	17.56	0.00%	17.56	0.00%	17.56	0.00%
ECAR	0.095	9.61	0.99%	8.42	1.13%	5.61	1.70%	7.79	1.22%	7.79	1.22%
ERCOT	0.020	12.04	0.17%	8.09	0.25%	6.34	0.32%	9.10	0.22%	9.15	0.22%
FRCC	0.007	12.89	0.06%	11.00	0.07%	8.66	0.08%	9.63	0.08%	11.81	0.06%
HICC	0.000	24.43	0.00%	24.43	0.00%	24.43	0.00%	24.43	0.00%	24.43	0.00%
MAAC	0.021	11.54	0.18%	9.33	0.22%	6.61	0.31%	9.39	0.22%	9.59	0.22%
MAIN	0.051	10.00	0.51%	8.25	0.62%	4.61	1.11%	7.74	0.66%	7.64	0.67%
MAPP	0.031	8.97	0.34%	7.09	0.43%	5.04	0.61%	6.32	0.49%	7.02	0.44%
NPCC	0.007	17.53	0.04%	13.15	0.05%	8.57	0.08%	14.33	0.05%	13.94	0.05%
SERC	0.046	9.12	0.50%	7.85	0.58%	5.69	0.80%	6.80	0.67%	7.74	0.59%
SPP	0.036	9.25	0.38%	7.91	0.45%	5.98	0.60%	6.21	0.57%	7.88	0.45%
WECC	0.006	11.32	0.05%	10.32	0.06%	7.20	0.08%	9.91	0.06%	9.95	0.06%
U.S.	**0.036**	**10.95**	**0.33%**	**9.23**	**0.39%**	**6.03**	**0.59%**	**10.10**	**0.35%**	**9.03**	**0.40%**

Table 7-2: Projected 2014 Price (Cents per KWh of Sales) and Potential Price Increase Due to Compliance Costs by NERC Region and Regulatory Option ($2010)[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 5											
ASCC	0.000	17.56	0.00%	17.56	0.00%	17.56	0.00%	17.56	0.00%	17.56	0.00%
ECAR	0.159	9.61	1.66%	8.42	1.89%	5.61	2.84%	7.79	2.04%	7.79	2.04%
ERCOT	0.041	12.04	0.34%	8.09	0.51%	6.34	0.65%	9.10	0.45%	9.15	0.45%
FRCC	0.032	12.89	0.25%	11.00	0.29%	8.66	0.37%	9.63	0.33%	11.81	0.27%
HICC	0.000	24.43	0.00%	24.43	0.00%	24.43	0.00%	24.43	0.00%	24.43	0.00%
MAAC	0.036	11.54	0.31%	9.33	0.38%	6.61	0.54%	9.39	0.38%	9.59	0.37%
MAIN	0.068	10.00	0.68%	8.25	0.82%	4.61	1.47%	7.74	0.88%	7.64	0.89%
MAPP	0.053	8.97	0.59%	7.09	0.75%	5.04	1.05%	6.32	0.84%	7.02	0.76%
NPCC	0.009	17.53	0.05%	13.15	0.07%	8.57	0.11%	14.33	0.06%	13.94	0.07%
SERC	0.076	9.12	0.84%	7.85	0.97%	5.69	1.34%	6.80	1.12%	7.74	0.99%
SPP	0.051	9.25	0.55%	7.91	0.64%	5.98	0.85%	6.21	0.82%	7.88	0.64%
WECC	0.006	11.32	0.06%	10.32	0.06%	7.20	0.09%	9.91	0.06%	9.95	0.06%
U.S.	**0.059**	**10.95**	**0.54%**	**9.23**	**0.64%**	**6.03**	**0.99%**	**10.10**	**0.59%**	**9.03**	**0.66%**

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

Source: U.S. EPA Analysis, 2013; U.S. DOE, 2010b; U.S. DOE, 2009c

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 plants are not able to pass their compliance costs to consumers through higher electricity rates, this analysis overstates the potential impact of the proposed 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.

Further, the compliance costs used in this analysis do not reflect anticipated unit retirements and conversions announced between August 2012 and April 2013, and announced retirements, repowerings, and conversions that are scheduled to occur by 2022. As discussed in *Chapter 3*, accounting for these changes would reduce total annualized compliance 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 proposed 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 2014 by NERC region.[94]
- 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 2014 from *AEO2010*.[95,96] For ASCC and HICC, EPA used the historical quantity of electricity sales (in MWh) for the year 2009 from the 2009 EIA-861 database and assumed that total average electricity sales would remain unchanged through 2014.
- To calculate average annual electricity sales per household, EPA divided the total quantity of *residential* sales (in MWh) for 2009 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 2009 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 2014 as in 2009.
- 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 2009 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 ECAR, while regions facing the lowest non-zero cost vary (MAPP, WECC, or NPCC, depending on the option). In particular for the four preferred options, the results for Option 3a show the average annual cost per residential household increasing by $0 to $1.69 depending on the region, with a national average of $0.48. For Option 3b, the results show the average annual cost per residential household increasing by $0 to $2.29, with a national average of $0.75. For Option 3, the average annual cost per residential household increases by $0 to $4.40, with a national average of $1.59. Finally, for Option 4a, the average annual cost per residential household increases by $0 to $7.22, depending on the region, with a national average of $2.69.

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

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

96 EPA used *AEO2010* as opposed to more current AEO data available at the time of this analysis because the NERC-region definition used in the *AEO2010* publication aligned better with the NERC-region definition in the EIA-861 database also used for this analysis.

Table 7-3: Average Annual Cost per Household in 2014 by NERC Region and Regulatory Option ($2010)[a]

NERC Region	Total Annual Compliance Cost (at 2014; $2010)	Total Electricity Sales (at 2014; MWh)	Compliance Cost per Unit of Sales ($2010/MWh)	Residential Electricity Sales (at 2014; MWh)	Number of Households (at 2014)	Residential Sales per Residential Consumer (MWh)	Compliance Cost per Household ($2010)
Option 3a							
ASCC	$0	6,427,040	$0.00	2,160,441	280,020	7.72	$0.00
ECAR	$89,589,899	562,390,686	$0.16	180,355,570	17,019,960	10.60	$1.69
ERCOT	$0	300,895,599	$0.00	93,178,829	6,681,075	13.95	$0.00
FRCC	$0	226,942,169	$0.00	108,118,711	7,967,879	13.57	$0.00
HICC	$0	10,125,934	$0.00	3,055,241	412,838	7.40	$0.00
MAAC	$0	287,861,511	$0.00	97,580,958	9,941,282	9.82	$0.00
MAIN	$9,520,495	275,205,261	$0.03	81,117,687	8,936,167	9.08	$0.31
MAPP	$226,272	162,173,447	$0.00	54,572,006	5,196,499	10.50	$0.01
NPCC	$0	286,114,145	$0.00	92,652,334	12,660,375	7.32	$0.00
SERC	$64,289,350	836,496,826	$0.08	326,309,750	23,094,466	14.13	$1.09
SPP	$792,306	197,315,811	$0.00	67,055,796	5,389,191	12.44	$0.05
WECC	$3,660,919	679,947,516	$0.01	240,839,970	26,403,511	9.12	$0.05
U.S.	**$168,079,242**	**3,831,895,945**	**$0.04**	**1,346,997,293**	**123,983,263**	**10.86**	**$0.48**
Option 3b							
ASCC	$0	6,427,040	$0.00	2,160,441	280,020	7.72	$0.00
ECAR	$121,509,392	562,390,686	$0.22	180,355,570	17,019,960	10.60	$2.29
ERCOT	$9,073,578	300,895,599	$0.03	93,178,829	6,681,075	13.95	$0.42
FRCC	$0	226,942,169	$0.00	108,118,711	7,967,879	13.57	$0.00
HICC	$0	10,125,934	$0.00	3,055,241	412,838	7.40	$0.00
MAAC	$0	287,861,511	$0.00	97,580,958	9,941,282	9.82	$0.00
MAIN	$9,520,495	275,205,261	$0.03	81,117,687	8,936,167	9.08	$0.31
MAPP	$226,272	162,173,447	$0.00	54,572,006	5,196,499	10.50	$0.01
NPCC	$0	286,114,145	$0.00	92,652,334	12,660,375	7.32	$0.00
SERC	$118,319,085	836,496,826	$0.14	326,309,750	23,094,466	14.13	$2.00
SPP	$2,283,936	197,315,811	$0.01	67,055,796	5,389,191	12.44	$0.14
WECC	$3,660,919	679,947,516	$0.01	240,839,970	26,403,511	9.12	$0.05
U.S.	**$264,593,677**	**3,831,895,945**	**$0.07**	**1,346,997,293**	**123,983,263**	**10.86**	**$0.75**
Option 1							
ASCC	$0	6,427,040	$0.00	2,160,441	280,020	7.72	$0.00
ECAR	$96,782,075	562,390,686	$0.17	180,355,570	17,019,960	10.60	$1.82
ERCOT	$26,339,280	300,895,599	$0.09	93,178,829	6,681,075	13.95	$1.22
FRCC	$2,970,728	226,942,169	$0.01	108,118,711	7,967,879	13.57	$0.18
HICC	$0	10,125,934	$0.00	3,055,241	412,838	7.40	$0.00
MAAC	$1,743,343	287,861,511	$0.01	97,580,958	9,941,282	9.82	$0.06
MAIN	$14,512,921	275,205,261	$0.05	81,117,687	8,936,167	9.08	$0.48
MAPP	$15,007,890	162,173,447	$0.09	54,572,006	5,196,499	10.50	$0.97
NPCC	$1,252,830	286,114,145	$0.00	92,652,334	12,660,375	7.32	$0.03
SERC	$96,452,227	836,496,826	$0.12	326,309,750	23,094,466	14.13	$1.63
SPP	$9,628,222	197,315,811	$0.05	67,055,796	5,389,191	12.44	$0.61
WECC	$1,200,969	679,947,516	$0.00	240,839,970	26,403,511	9.12	$0.02
U.S.	**$265,890,484**	**3,831,895,945**	**$0.07**	**1,346,997,293**	**123,983,263**	**10.86**	**$0.75**
Option 2							
ASCC	$0	6,427,040	$0.00	2,160,441	280,020	7.72	$0.00
ECAR	$143,970,919	562,390,686	$0.26	180,355,570	17,019,960	10.60	$2.71
ERCOT	$37,299,017	300,895,599	$0.12	93,178,829	6,681,075	13.95	$1.73
FRCC	$11,182,413	226,942,169	$0.05	108,118,711	7,967,879	13.57	$0.67
HICC	$0	10,125,934	$0.00	3,055,241	412,838	7.40	$0.00
MAAC	$9,494,272	287,861,511	$0.03	97,580,958	9,941,282	9.82	$0.32
MAIN	$21,022,444	275,205,261	$0.08	81,117,687	8,936,167	9.08	$0.69
MAPP	$20,112,267	162,173,447	$0.12	54,572,006	5,196,499	10.50	$1.30
NPCC	$2,961,927	286,114,145	$0.01	92,652,334	12,660,375	7.32	$0.08
SERC	$129,799,304	836,496,826	$0.16	326,309,750	23,094,466	14.13	$2.19

Table 7-3: Average Annual Cost per Household in 2014 by NERC Region and Regulatory Option ($2010)[a]

NERC Region	Total Annual Compliance Cost (at 2014; $2010)	Total Electricity Sales (at 2014; MWh)	Compliance Cost per Unit of Sales ($2010/MWh)	Residential Electricity Sales (at 2014; MWh)	Number of Households (at 2014)	Residential Sales per Residential Consumer (MWh)	Compliance Cost per Household ($2010)
SPP	$15,230,666	197,315,811	$0.08	67,055,796	5,389,191	12.44	$0.96
WECC	$2,195,920	679,947,516	$0.00	240,839,970	26,403,511	9.12	$0.03
U.S.	**$393,269,150**	**3,831,895,945**	**$0.10**	**1,346,997,293**	**123,983,263**	**10.86**	**$1.12**
Option 3							
ASCC	$0	6,427,040	$0.00	2,160,441	280,020	7.72	$0.00
ECAR	$233,560,818	562,390,686	$0.42	180,355,570	17,019,960	10.60	$4.40
ERCOT	$37,299,017	300,895,599	$0.12	93,178,829	6,681,075	13.95	$1.73
FRCC	$11,182,413	226,942,169	$0.05	108,118,711	7,967,879	13.57	$0.67
HICC	$0	10,125,934	$0.00	3,055,241	412,838	7.40	$0.00
MAAC	$9,494,272	287,861,511	$0.03	97,580,958	9,941,282	9.82	$0.32
MAIN	$30,542,939	275,205,261	$0.11	81,117,687	8,936,167	9.08	$1.01
MAPP	$20,338,539	162,173,447	$0.13	54,572,006	5,196,499	10.50	$1.32
NPCC	$2,961,927	286,114,145	$0.01	92,652,334	12,660,375	7.32	$0.08
SERC	$194,088,655	836,496,826	$0.23	326,309,750	23,094,466	14.13	$3.28
SPP	$16,022,972	197,315,811	$0.08	67,055,796	5,389,191	12.44	$1.01
WECC	$5,856,839	679,947,516	$0.01	240,839,970	26,403,511	9.12	$0.08
U.S.	**$561,348,392**	**3,831,895,945**	**$0.15**	**1,346,997,293**	**123,983,263**	**10.86**	**$1.59**
Option 4a							
ASCC	$0	6,427,040	$0.00	2,160,441	280,020	7.72	$0.00
ECAR	$382,925,214	562,390,686	$0.68	180,355,570	17,019,960	10.60	$7.22
ERCOT	$56,007,875	300,895,599	$0.19	93,178,829	6,681,075	13.95	$2.60
FRCC	$11,182,413	226,942,169	$0.05	108,118,711	7,967,879	13.57	$0.67
HICC	$0	10,125,934	$0.00	3,055,241	412,838	7.40	$0.00
MAAC	$28,546,920	287,861,511	$0.10	97,580,958	9,941,282	9.82	$0.97
MAIN	$77,380,834	275,205,261	$0.28	81,117,687	8,936,167	9.08	$2.55
MAPP	$31,521,541	162,173,447	$0.19	54,572,006	5,196,499	10.50	$2.04
NPCC	$2,966,374	286,114,145	$0.01	92,652,334	12,660,375	7.32	$0.08
SERC	$295,056,291	836,496,826	$0.35	326,309,750	23,094,466	14.13	$4.98
SPP	$45,223,870	197,315,811	$0.23	67,055,796	5,389,191	12.44	$2.85
WECC	$16,944,862	679,947,516	$0.02	240,839,970	26,403,511	9.12	$0.23
U.S.	**$947,756,195**	**3,831,895,945**	**$0.25**	**1,346,997,293**	**123,983,263**	**10.86**	**$2.69**
Option 4							
ASCC	$0	6,427,040	$0.00	2,160,441	280,020	7.72	$0.00
ECAR	$535,051,837	562,390,686	$0.95	180,355,570	17,019,960	10.60	$10.08
ERCOT	$60,192,862	300,895,599	$0.20	93,178,829	6,681,075	13.95	$2.79
FRCC	$16,638,136	226,942,169	$0.07	108,118,711	7,967,879	13.57	$0.99
HICC	$0	10,125,934	$0.00	3,055,241	412,838	7.40	$0.00
MAAC	$59,894,195	287,861,511	$0.21	97,580,958	9,941,282	9.82	$2.04
MAIN	$140,243,878	275,205,261	$0.51	81,117,687	8,936,167	9.08	$4.63
MAPP	$49,842,966	162,173,447	$0.31	54,572,006	5,196,499	10.50	$3.23
NPCC	$18,965,753	286,114,145	$0.07	92,652,334	12,660,375	7.32	$0.49
SERC	$382,915,981	836,496,826	$0.46	326,309,750	23,094,466	14.13	$6.47
SPP	$70,233,678	197,315,811	$0.36	67,055,796	5,389,191	12.44	$4.43
WECC	$39,270,065	679,947,516	$0.06	240,839,970	26,403,511	9.12	$0.53
U.S.	**$1,373,249,350**	**3,831,895,945**	**$0.36**	**1,346,997,293**	**123,983,263**	**10.86**	**$3.89**
Option 5							
ASCC	$0	6,427,040	$0.00	2,160,441	280,020	7.72	$0.00
ECAR	$894,852,326	562,390,686	$1.59	180,355,570	17,019,960	10.60	$16.86
ERCOT	$124,331,807	300,895,599	$0.41	93,178,829	6,681,075	13.95	$5.76
FRCC	$72,258,936	226,942,169	$0.32	108,118,711	7,967,879	13.57	$4.32
HICC	$0	10,125,934	$0.00	3,055,241	412,838	7.40	$0.00
MAAC	$103,253,011	287,861,511	$0.36	97,580,958	9,941,282	9.82	$3.52

Table 7-3: Average Annual Cost per Household in 2014 by NERC Region and Regulatory Option ($2010)[a]

NERC Region	Total Annual Compliance Cost (at 2014; $2010)	Total Electricity Sales (at 2014; MWh)	Compliance Cost per Unit of Sales ($2010/MWh)	Residential Electricity Sales (at 2014; MWh)	Number of Households (at 2014)	Residential Sales per Residential Consumer (MWh)	Compliance Cost per Household ($2010)
MAIN	$186,704,789	275,205,261	$0.68	81,117,687	8,936,167	9.08	$6.16
MAPP	$86,137,684	162,173,447	$0.53	54,572,006	5,196,499	10.50	$5.58
NPCC	$26,280,950	286,114,145	$0.09	92,652,334	12,660,375	7.32	$0.67
SERC	$639,838,743	836,496,826	$0.76	326,309,750	23,094,466	14.13	$10.81
SPP	$99,911,219	197,315,811	$0.51	67,055,796	5,389,191	12.44	$6.30
WECC	$43,712,271	679,947,516	$0.06	240,839,970	26,403,511	9.12	$0.59
U.S.	**$2,277,281,737**	**3,831,895,945**	**$0.59**	**1,346,997,293**	**123,983,263**	**10.86**	**$6.46**

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

Source: U.S. EPA Analysis, 2013; U.S. DOE, 2010b; U.S. DOE, 2009c

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 plants are not able to pass their compliance costs to consumers through higher electricity rates, this analysis overstates the potential impact of the proposed 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. 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 does not account for rate structures – e.g., lifeline rates – which could moderate the impact of otherwise increased rates on lower income households.

Further, the compliance costs used in this analysis do not reflect anticipated unit retirements and conversions announced between August 2012 and April 2013, and announced retirements, repowerings, and conversions that are scheduled to occur by 2022. As discussed in *Chapter 3*, accounting for these changes would reduce total annualized compliance costs.

8 Assessing the Potential Impact of the Proposed 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 regulatory proposals on small entities,[97] 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 industry guidelines and standards, EPA assessed whether the proposed ELGs would have "a significant impact on a substantial number of small entities" (SISNOSE). This assessment involved the following steps:

- Determining the domestic parent entities of steam electric plants.
- Determining which of those domestic parent entities are small entities, based on Small Business Administration (SBA) 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 eight 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 proposed ELGs on small entities (*Section 8.4*).

97 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 proposed ELGs.

8.1.1 Determining Parent Entity of Steam Electric 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)[98] in at least one surveyed steam electric 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), 2009 databases published by the Department of Energy"s Energy Information Administration (EIA) (U.S. DOE, 2009b; U.S DOE, 2009c), and corporate and financial websites.

8.1.2 Determining Whether Parent Entities of Steam Electric Plants Are Small

EPA identified the size of each parent entity identified in the previous step using the current Small Business Administration (SBA) size threshold guidelines.[99] The criteria for entity size determination vary by the organization/operation category of the parent entity, as follows:

- Privately owned entities
  - Privately owned entities include investor-owned utilities, non-utility entities, and entities with a primary business other than electric power generation.
  - For entities with electric power generation as a primary business, small entities are those with total annual electric output less than 4 million MWh.
  - For entities with a primary business other than electric power generation, the relevant size criteria are based on revenue or number of employees by the North American Industry Classification System (NAICS) sector (see *Table 8-1*): [100]

Table 8-1: NAICS Codes and SBA Size Standards for Majority Owners Entities of Steam Electric Plants with a Primary Business Other Than Electric Power Generation[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	$7 million in revenue
221210	Natural Gas Distribution	500 Employees
221310	Water Supply and Irrigation Systems	$7 million in revenue
221330	Steam and Air-Conditioning Supply	$12.5 million in revenue
237130	Power and Communication Line and Related Structures Construction	$33.5 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

[98] 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.

[99] To conduct this analysis, EPA used SBA size threshold guidelines published in 2012. The 2012 set of small business size guidelines are available online at: http://www.sba.gov/sites/default/files/files/Size_Standards_Table.pdf.

[100] 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 Majority Owners Entities of Steam Electric Plants with a Primary Business Other Than Electric Power Generation[a]

NAICS Code	NAICS Description	SBA Size Standard[b]
423510	Metal Service Centers and Other Metal Merchant Wholesalers	100 Employees
486110	Pipeline Transportation of Crude Oil	1,500 Employees
522110	Commercial Banking	$175 million in assets
523110	Investment Banking and Securities Dealing	$7 million in revenue
523910	Miscellaneous Intermediation	$7 million in revenue
523920	Portfolio Management	$7 million in revenue
524113	Direct Life Insurance Carriers	$7 million in revenue
524126	Direct Property and Casualty Insurance Carriers	1,500 employees
525910	Open-End Investment Funds	$7 million in revenue
541614	Process, Physical Distribution and Logistics Consulting Services	$14 million in revenue
541690	Other Scientific and Technical Consulting Services	$14 million in revenue
551111	Offices of Bank Holding Companies	$7 million in revenue
551112	Offices of Other Holding Companies	$7 million in revenue
562219	Other Nonhazardous Waste Treatment and Disposal	$12.5 million in revenue[c]

Source: SBA, 2013

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

b. Based on size standards effective at the time EPA conducted this analysis (SBA size standards, effective October 1, 2012)

c. EPA is aware that SBA revised the size standard applicable to this sector, effective January 7, 2013 (from $12.5 million in revenue to $35.5 million in revenue); EPA used the size standards effective at the time the analyses were completed and will update the size standards as part of revisions to support final rulemaking.

- 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 rural electric cooperative entities are those with total annual electric output less than 4 million MWh.

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:

- **Electricity output**: EPA used entity-level electricity sales 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 electricity sales reported in the industry survey, EPA used electricity sales from corporate/financial websites, if those values were available; to be consistent with the data collected through the industry survey, EPA tried to obtain electricity sales for at least one of the three survey years (i.e., 2007, 2008, and/or 2009) and used the average of reported values. If electricity sales were not reported on corporate/financial websites, the Agency used 2007-2009 average electricity sales values (retail plus wholesale) from the EIA-861 database or, for plants not listed in the EIA-861 database, the 2007-2009 average net electricity generation values from the EIA-906/920/923 database (U.S. DOE, 2009b; U.S. DOE, 2009c).

- **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).
- **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 revenue values from corporate/financial websites.
- **Population**: Population data for municipalities and other non-state political subdivisions were obtained from the U.S. Census Bureau (estimated population for 2010).

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 plants as a range, based on alternative assumptions about the possible ownership of potentially regulated electric power plants by small entities. EPA considered 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 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 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 plants as well as the number and percentage of those entities determined to be small. *Table 8-3* presents the distribution of steam electric plants by ownership type and owner size. Analysis results are presented by ownership type for the eight 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 1,079 steam electric plants (for Case 1 and Case 2, respectively). A typical parent entity on average is estimated to own between 2 and 4 steam electric plants (for Case 2 and Case 1, respectively). The Agency estimates that between 97 (40 percent) and 170 (34 percent) parent entities are small under Case 1 and Case 2, respectively.

These 97 and 170 small entities (*Table 8-2*) own 189 steam electric plants (*Table 8-3*), or approximately 18 percent of all steam electric plants. Across ownership types, municipalities represent the largest share of small entities (57 percent) under Case 1 and nonutilities represent the largest share of small entities (47 percent) under Case 2; municipalities account for the largest share of steam electric plants owned by small entities (38 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 plants[b]			Case 2: Upper bound estimate of number of entities owning steam electric plants[b]		
		Total	Small[c]	% Small	Total	Small[c]	% Small
Cooperative	4,000,000 MWh output	30	13	43.3%	52	21	40.7%
Federal	assumed large	2	0	0.0%	4	0	0.0%
Investor-owned	4,000,000 MWh output	97	27	27.8%	244	64	26.3%
Municipality	50,000 population served	65	37	56.9%	101	46	45.3%
Nonutility	4,000,000 MWh output	35	18	51.4%	73	34	46.8%
Other Political Subdivision	50,000 population served	12	2	16.7%	30	4	14.2%
State	assumed large	2	0	0.0%	2	0	0.0%
Total		**243**	**97**	**39.9%**	**507**	**170**	**33.5%**

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, 92 entities, 14 of which are small, own steam electric plants that are expected to incur compliance technology costs under at least one regulatory option under both Case 1 and Case 2.
c. EPA was unable to determine the size of 10 parent entities; for this analysis, these entities are assumed to be small.
Source: U.S. EPA Analysis, 2013

Table 8-3: Steam Electric Plants by Ownership Type and Size, 2010

Ownership Type	Number of Steam Electric Plants[a,b,c,d]		
	Total	Small	% Small
Cooperative	67	22	33.3%
Federal	15	0	0.0%
Investor-owned	680	87	12.8%
Municipality	122	47	38.5%
Nonutility	150	29	19.3%
Other Political Subdivisions	41	4	10.6%
State	5	0	0.0%
Total	**1,079**	**189**	**17.5%**

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 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.
d. Of these, 277 steam electric plants are expected to incur compliance technology costs under at least one regulatory option; 14 of these 277 steam electric plants are owned by small entities.
Source: U.S. EPA Analysis, 2013

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 proposed 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 proposed regulation 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 regulation 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 proposed 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 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 plants.[101]

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

8.2 Key Findings for Regulatory Options

As described above, 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 plants; lower bound estimate of total compliance costs that an entity may incur.

As reported in *Table 8-4*, in terms of *number* of entities in each of the impact categories, analysis results are the same under Case 1 and Case 2; however, these numbers represent different percentages of all small entities owning steam electric plants under each weighting Case. EPA estimates that between 0 and 12 small entities owning steam electric plants would incur costs exceeding 1 percent of revenue, and that between 0 and 7 small entities would incur costs of at least 3 percent of revenue, depending on the regulatory option. Specifically for the four preferred regulatory options, the Agency estimates that under Options 3a and 3b, no small entities would incur costs of at least 1 percent; under Option 3, 5 small entities (3 to 5 percent of small entities) would incur costs of at least 1 percent of revenue and 3 small entities (2 to 3 percent) would incur costs of at least 3 percent of revenue. Under Option 4a, 6 small entities (4 to 6 percent) and 4 small entities (2 to 4 percent) would incur costs of at least 1 percent and 3 percent of revenue, respectively.

On the basis of *percentage* of small entities by entity type, the analysis shows a small percentage of small business or government entities (generally less than 10 percent) incurring an impact at either the 1 or

[101] To evaluate the sensitivity of the results to the cost pass-through assumption, EPA also analyzed Option 3 assuming that steam electric plants would be able to pass through a fraction of their compliance costs to consumers through higher electricity rates (Fifty-Percent Cost-Pass-Through). EPA used 50 percent as an illustrative cost-pass through assumption. The results of this sensitivity analysis are reported in *Appendix B*.

3 percent of revenue levels. As noted above, no small entity has cost exceedaing 1 percent of revenue under Options 3a and 3b. Under Option 3, between 6 and 8 percent of small government entities have costs exceeding 1 percent of revenue; under Option 4a, between 9 and 15 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 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 plants				Case 2: Upper bound estimate of number of entities owning steam electric plants			
	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 3a								
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 3b								
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 1								
Cooperative	2	15.4%	2	15.4%	2	9.4%	2	9.4%
Investor-Owned	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Municipality	1	2.7%	1	2.7%	1	2.2%	1	2.2%
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]	***2***	***3.4%***	***2***	***3.4%***	***2***	***1.7%***	***2***	***1.7%***
Small Government[d]	***1***	***2.6%***	***1***	***2.6%***	***1***	***2.0%***	***1***	***2.0%***
Total	**3**	**3.1%**	**3**	**3.1%**	**3**	**1.8%**	**3**	**1.8%**
Option 2								
Cooperative	2	15.4%	2	15.4%	2	9.4%	2	9.4%
Investor-Owned	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Municipality	3	8.1%	1	2.7%	3	6.5%	1	2.2%
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]	***2***	***3.4%***	***2***	***3.4%***	***2***	***1.7%***	***2***	***1.7%***
Small Government[d]	***3***	***7.7%***	***1***	***2.6%***	***3***	***6.0%***	***1***	***2.0%***
Total	**5**	**5.2%**	**3**	**3.1%**	**5**	**2.9%**	**3**	**1.8%**
Option 3								
Cooperative	2	15.4%	2	15.4%	2	9.4%	2	9.4%
Investor-Owned	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Municipality	3	8.1%	1	2.7%	3	6.5%	1	2.2%
Nonutility	0	0.0%	0	0.0%	0	0.0%	0	0.0%

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 plants				Case 2: Upper bound estimate of number of entities owning steam electric plants			
	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
Other Political Subdivision	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Small Business[c]	***2***	***3.4%***	***2***	***3.4%***	***2***	***1.7%***	***2***	***1.7%***
Small Government[d]	***3***	***7.7%***	***1***	***2.6%***	***3***	***6.0%***	***1***	***2.0%***
Total	**5**	**5.2%**	**3**	**3.1%**	**5**	**2.9%**	**3**	**1.8%**
Option 4a								
Cooperative	2	15.4%	2	15.4%	2	9.4%	2	9.4%
Investor-Owned	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Municipality	4	10.8%	2	5.4%	4	8.7%	2	4.4%
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]	***2***	***3.4%***	***2***	***3.4%***	***2***	***1.7%***	***2***	***1.7%***
Small Government[d]	***4***	***10.3%***	***2***	***5.1%***	***4***	***8.0%***	***2***	***4.0%***
Total	**6**	**6.2%**	**4**	**4.1%**	**6**	**3.5%**	**4**	**2.4%**
Option 4								
Cooperative	2	15.4%	2	15.4%	2	9.4%	2	9.4%
Investor-Owned	1	3.7%	0	0.0%	1	1.6%	0	0.0%
Municipality	8	21.6%	2	5.4%	8	17.4%	2	4.4%
Nonutility	1	5.6%	0	0.0%	1	2.9%	0	0.0%
Other Political Subdivision	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Small Business[c]	***4***	***6.9%***	***2***	***3.4%***	***4***	***3.3%***	***2***	***1.7%***
Small Government[d]	***8***	***20.5%***	***2***	***5.1%***	***8***	***15.9%***	***2***	***4.0%***
Total	**12**	**12.4%**	**4**	**4.1%**	**12**	**7.1%**	**4**	**2.4%**
Option 5								
Cooperative	2	15.4%	2	15.4%	2	9.4%	2	9.4%
Investor-Owned	1	3.7%	1	3.7%	1	1.6%	1	1.6%
Municipality	8	21.6%	4	10.8%	8	17.4%	4	8.7%
Nonutility	1	5.6%	0	0.0%	1	2.9%	0	0.0%
Other Political Subdivision	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Small Business[c]	***4***	***6.9%***	***3***	***5.2%***	***4***	***3.3%***	***3***	***2.5%***
Small Government[d]	***8***	***20.5%***	***4***	***10.3%***	***8***	***15.9%***	***4***	***8.0%***
Total	**12**	**12.4%**	**7**	**7.2%**	**12**	**7.1%**	**7**	**4.1%**

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 97 (Case 1) and 170 (Case 2) small entities owning steam electric 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, 2013

8.3 Uncertainties and Limitations

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 10 parent entities and assumed that these entities are small; this assumption may overstate the number of small entities that own steam electric 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 2014 values, the number of small parent entities of steam electric 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 2014 entity revenue values are different from those estimated using data for 2007, 2008, and/or 2009, the impact of the proposed ELGs on parent entities of steam electric 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 proposed ELGs on small entities.
- As discussed in *Chapter 3*, the compliance costs used in this analysis do not reflect anticipated unit retirements and conversions announced between August 2012 and April 2013, and announced retirements, repowerings, and conversions that are scheduled to occur by 2022. Accounting for these changes would reduce total annualized compliance 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 proposals on small entities and to analyze alternatives that minimize those impacts. In the preamble to this rule, EPA describes how it explicitly considered potential impacts on small entities in designing the regulatory options. For example, by differentiating requirements for oil-fired units and small units of less than 50 MW in capacity, the proposed ELGs reduce compliance costs for small entities that own plants with one or more such units. Based on the sensitivity analyses discussed in *Appendix B*, EPA estimates that 12 small entities incur compliance costs under Option 3 when units of all sizes are subject to the same requirements, only 7 small entities incur compliance costs with the differentiated requirements. Under Option 4, the differentiated requirements reduce the number of small entities incurring costs from 21 entities (when all units are subject to the ELGs) to 14 entities (with differentiated requirements for oil-fired units and small units less than 50 MW). The proposed period of implementation 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 or more in any one year. 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 $13.8 million under Option 3a to $406.2 million under Option 5.[102,103] The four preferred regulatory options have maximum costs in any given year to government entities of $13.8 million, $31.9 million, $109.5 million, and $141.8 million, respectively for Options 3a, 3b, 3, and 4a. The *maximum* cost *in any given year* to the private sector range from $291.5 million under Option 3a, to $4,189.1 million under Option 5. The four preferred regulatory options have maximum costs in any given year to the private sector of $291.5 million, $614.0 million, $1,040.9 million, and $1,943.7 million, respectively for Options 3a, 3b, 3, and 4a.

From these cost values, EPA determined that the proposed ELGs contain a federal mandate that may result in expenditures of $100 million or more for State, local, and Tribal governments, in the aggregate, or the private sector in any one year. Accordingly, under §202 of the UMRA, EPA has prepared a written statement, presented in the preamble to the proposed 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 11: Assessment of Total Social Costs* of the *Benefit and Cost Analysis for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* report (*BCA*) (U.S. EPA, 2013b; DCN SE03172). Specifically, this analysis uses costs in 2014 stated in 2010 dollars; cost values are weighted estimates unless otherwise noted (see *Technical Development Document (TDD)* for discussion on development of sample weights) (U.S. EPA, 2013a; DCN SE01964). As discussed in *Chapter 10: Other Administrative Requirements* (see *Section 10.7: Paperwork Reduction Act of 1995*) in this document, the proposed ELGs would not significantly change the reporting and recordkeeping burden for the review, oversight, and administration of the rule relative to existing requirements; consequently, National

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

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

Pollutant Discharge Elimination System (NPDES) permitting authorities are expected to 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 11*.

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 plants. The use of the phrase "government entities" in this section does *not* include the federal government, which owns 15 of the 1,079 steam electric 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 plants. As discussed earlier, government entities would not incur significant incremental *administrative costs* to implement the rule, regardless of whether they own steam electric plants.

The determination of owning entities, their type, and their size is detailed in *Chapter 3: Compliance Costs* and *Chapter 7: Regulatory Flexibility Act Analysis*.

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

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

Entity Type	Parent Entities[a]	Steam Electric 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, 2013

Out of 1,079 steam electric plants, 168 are owned by 79 government entities.[104] 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).

As presented in *Table 9-2*, government entities are projected to incur the lowest compliance costs under Option 3a and the highest compliance costs under Option 5.

Under Option 3a, compliance costs for government entities are approximately $6.6 million in the aggregate, with an average of $0.04 million per plant. State government entities account for the largest share of this cost (71 percent), followed by municipalities (29 percent). Other political subdivisions do not incur costs under this option. The average cost per plant to States is $0.9 million, compared to $0.02 million for plants owned

104 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: Economic Impact Screening Analysis*.

by municipalities. The maximum annualized compliance costs estimated to be incurred by any single government-owned plant is $4.5 million for a State-owned plant and $1.2 million for a municipal plant. The average cost per MW of government-owned generating capacity is estimated to be $104 per MW, with the highest average unit cost incurred by States ($891 per MW) and the lowest average unit cost incurred by other political subdivisions ($0 per MW).

Under Option 3b, government entities incur annualized total cost of approximately $10 million to comply with regulatory requirements, with the largest share of compliance costs again borne by State government entities (81 percent), followed by municipalities (19 percent). Other political subdivisions have no costs. Overall, costs for a government-owned plant are estimated to be $0.1 million per plant, with average per plant costs of $1.6 million for States and $0.02 million for municipalities. The average cost per MW of government-owned generating capacity is estimated to be $159 per MW, with the highest average unit cost incurred by State government entities ($1,545 per MW) and the lowest average unit cost incurred by other political subdivisions ($0 per MW).

Under Option 3, total annualized compliance costs to government entities are estimated to be approximately $31 million with an average of $0.2 million per plant. Municipalities and State government entities each account for approximately the same share of these costs (45 percent and 46 percent, respectively) followed by other political subdivisions (10 percent). The largest annualized compliance cost to any government-owned plant under Option 3 is $10.5 million, incurred by a State-owned plant. State government entities are also expected to incur the highest average cost per MW of capacity at $2,688 per MW.

For Option 4a, total annualized compliance costs are $40.9 million, with an average of $0.2 million per plant. State government entities and municipalities account for the majority of the total costs (51 percent and 41 percent, respectively) under this option, while political subdivisions account for the remaining 8 percent. State government entities incur both the highest annualized cost per MW of capacity ($3,996 per MW) and the largest annualized compliance cost of any given government-owned plant ($10.5 million).

Table 9-2: Compliance Costs to Government Entities Owning Steam Electric Plants (Millions; $2010)

Ownership Type	Number of Steam Electric Plants (weighted)[a,b]	Total Weighted, Annualized Pre-Tax Compliance Cost[a,b]	Average Annualized Compliance Cost per MW of Capacity[c]	Average Annualized Compliance Cost per Plant[d]	Maximum Annualized Compliance Cost per Plant[e]
Option 3a					
Municipality	122	$1.9	$58	$0.0	$1.2
Other Political Subdivision	41	$0.0	$0	$0.0	$0.0
State	5	$4.7	$891	$0.9	$4.5
Total	**168**	**$6.6**	**$104**	**$0.0**	**$4.5**
Option 3b					
Municipality	122	$1.9	$58	$0.0	$1.2
Other Political Subdivision	41	$0.0	$0	$0.0	$0.0
State	5	$8.1	$1,545	$1.6	$4.5
Total	**168**	**$10.0**	**$159**	**$0.1**	**$4.5**
Option 1					
Municipality	122	$6.2	$191	$0.1	$2.5
Other Political Subdivision	41	$2.3	$89	$0.1	$2.3
State	5	$7.1	$1,343	$1.4	$4.6
Total	**168**	**$15.5**	**$246**	**$0.1**	**$4.6**

Table 9-2: Compliance Costs to Government Entities Owning Steam Electric Plants (Millions; $2010)

Ownership Type	Number of Steam Electric Plants (weighted)[a,b]	Total Weighted, Annualized Pre-Tax Compliance Cost[a,b]	Average Annualized Compliance Cost per MW of Capacity[c]	Average Annualized Compliance Cost per Plant[d]	Maximum Annualized Compliance Cost per Plant[e]
Option 2					
Municipality	122	$12.0	$368	$0.1	$3.4
Other Political Subdivision	41	$3.2	$128	$0.1	$3.2
State	5	$9.5	$1,797	$1.9	$6.0
Total	**168**	**$24.7**	**$391**	**$0.1**	**$6.0**
Option 3					
Municipality	122	$13.9	$426	$0.1	$4.1
Other Political Subdivision	41	$3.2	$128	$0.1	$3.2
State	5	$14.2	$2,688	$2.8	$10.5
Total	**168**	**$31.2**	**$495**	**$0.2**	**$10.5**
Option 4a					
Municipality	122	$16.6	$511	$0.1	$4.1
Other Political Subdivision	41	$3.2	$128	$0.1	$3.2
State	5	$21.1	$3,996	$4.2	$10.5
Total	**168**	**$40.9**	**$649**	**$0.2**	**$10.5**
Option 4					
Municipality	122	$41.4	$1,273	$0.3	$7.3
Other Political Subdivision	41	$5.4	$214	$0.1	$3.2
State	5	$30.2	$5,723	$6.0	$17.1
Total	**168**	**$77.0**	**$1,221**	**$0.5**	**$17.1**
Option 5					
Municipality	122	$70.0	$2,150	$0.6	$12.3
Other Political Subdivision	41	$10.3	$408	$0.3	$8.1
State	5	$48.7	$9,238	$9.7	$30.3
Total	**168**	**$128.9**	**$2,044**	**$0.8**	**$30.3**

a. One plant is owned by two entities with equal shares of ownership – a small municipality and a large cooperative; to assign unique ownership type and entity size to this plant, EPA assumed this plant to be owned by a small municipality. Another plant is owned by a large municipality and a large investor-owned utility with equal shares of ownership; to assign unique ownership type and entity size to this plant, EPA assumed this plant to be owned by a large municipality. For plants owned by multiple entities with equal ownership shares and in different ownership and/or size categories, EPA assigned plant-level compliances costs to appropriate ownership and size categories in accordance with plant ownership shares.
b. Plant counts and cost values are weighted estimates. See *TDD* for discussion on the development of plant sample weights.
c. Average cost per MW values were calculated using total compliance costs and capacity for all steam electric 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.
d. Average cost per plant values were calculated using the total number of steam electric plants owned by entities in a given ownership category.
e. Reflects maximum of un-weighted costs to surveyed plants only.
Source: U.S. EPA analysis, 2013

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 proposed 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 as estimated to be incurred by small governments with those values as 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 1,079 government-owned steam electric plants, EPA identified 51 plants that are owned by 49 small government entities. These 51 plants constitute approximately 30 percent of all government-owned plants.[105]

Table 9-3: Counts of Government-Owned Plants and Their Parent Entities, by Size

Entity Type	Entities[a]			Steam Electric Plants[b,c]		
	Large	Small	Total	Large	Small	Total
Municipality	28	37	65	75	47	**122**
Other Political Subdivision	10	2	12	37	4	**41**
State	2	0	2	5	0	**5**
Total	**40**	**49**	**89**	**117**	**51**	**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.

c. One plant is owned by two entities with equal shares of ownership - a small municipality and a large cooperative; to assign unique ownership type and entity size to this plant, EPA assumed this plant to be owned by a small municipality. Another plant is owned by a large municipality and a large investor-owned utility with equal shares of ownership; to assign unique ownership type and entity size to this plant, EPA assumed this plant to be owned by a large municipality.

Source: U.S. EPA analysis, 2013

As presented in *Table 9-4*, compliance costs are the lowest and associated regulatory impacts are the smallest under Option 3a and the largest under Option 5. Generally, compliance costs are lower for small governments compared to those to large governments and to small private entities in the aggregate and on a per plant basis under all regulatory options. No small entity incurs costs under Options 3a and 3b.

For Option 3, total annualized compliance costs are approximately $3 million for small government entities, compared to $30 million for large government entities and $15 million for small private entities. EPA estimates that, under Option 3, a small government entity would, on average, incur $0.1million in compliance costs per plant (but no more than $2.1 million per plant) compared to $0.2 million per plant (but no more than $10.5 million per plant) for plants owned by large governments, and $0.1 million per plant (but no more than $6.9 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 $473 per MW under Option 3, while for large government and small private entities unit costs are estimated to be $498 per MW and $339 per MW, respectively.

Option 4b shows similar general trends, with total annualized compliance costs for small government entities about one eighth those of large government entities, and about a third of those of small private entities ($4.8 million, $36.1 million, and $14.7 million, respectively). Average annualized costs for plants owned by small government entities are about $0.1 million, which is about the same as those owned by small private entities but a third of the annualized compliance costs for plants owned by large governments ($0.3 million).

As discussed in the preceding paragraphs 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 under all of the regulatory options. On a per MW basis, small governments face costs that tend to be slightly higher than large governments, but lower than those faced by private entities. One exception is Option 3 where average compliance cost per MW of plant capacity owned by small government entities is less than that estimated for large government 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

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

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 proposed ELGs.

Table 9-4: Compliance Costs for Electric Generators by Ownership Type and Size ($2010)

Ownership Type	Entity Size	Number of Plants (weighted)[a,b]	Total Annualized Pre-Tax Compliance Costs (Millions)[a,b]	Average Annualized Pre-tax Compliance Cost per MW of Capacity[c]	Average Annualized Pre-tax Compliance Cost per Plant (Millions)[d]	Maximum Annualized Pre-tax Compliance Cost per Plant (Millions)[e]
Option 3a						
Government (excl. federal)	Small	51	$0.0	$0	$0.0	$0.0
	Large	116	$6.6	$117	$0.1	$4.5
Private[f]	Small	138	$0.0	$0	$0.0	$0.0
	Large	759	$158.0	$257	$0.2	$25.2
All Plants[g]		**1,079**	**$164.5**	**$220**	**$0.2**	**$25.2**
Option 3b						
Government (excl. federal)	Small	51	$0.0	$0	$0.0	$0.0
	Large	116	$10.0	$179	$0.1	$4.5
Private[f]	Small	138	$0.0	$0	$0.0	$0.0
	Large	759	$215.0	$350	$0.3	$25.2
All Plants[g]		**1,079**	**$257.2**	**$344**	**$0.2**	**$25.2**
Option 1						
Government (excl. federal)	Small	51	$1.8	$264	$0.0	$1.4
	Large	116	$13.7	$244	$0.1	$4.6
Private[f]	Small	138	$10.6	$245	$0.1	$5.3
	Large	759	$198.8	$323	$0.3	$31.1
All Plants[g]		**1,079**	**$259.2**	**$346**	**$0.2**	**$31.1**
Option 2						
Government (excl. federal)	Small	51	$3.3	$473	$0.1	$2.1
	Large	116	$21.4	$381	$0.2	$6.0
Private[f]	Small	138	$14.7	$339	$0.1	$6.9
	Large	759	$297.5	$484	$0.4	$38.1
All Plants[g]		**1,079**	**$380.8**	**$509**	**$0.3**	**$38.1**
Option 3						
Government (excl. federal)	Small	51	$3.3	$473	$0.1	$2.1
	Large	116	$27.9	$498	$0.2	$10.5
Private[f]	Small	138	$14.7	$339	$0.1	$6.9
	Large	759	$455.5	$741	$0.6	$38.1
All Plants[g]		**1,079**	**$545.3**	**$728**	**$0.5**	**$38.1**
Option 4a						
Government (excl. federal)	Small	51	$4.8	$684	$0.1	$3.0
	Large	116	$36.1	$644	$0.3	$10.5
Private[f]	Small	138	$14.7	$339	$0.1	$6.9
	Large	759	$815.1	$1,326	$1.1	$40.4
All Plants[g]		**1,079**	**$914.7**	**$1,221**	**$0.8**	**$40.4**
Option 4						
Government (excl. federal)	Small	51	$10.6	$1,512	$0.2	$4.1
	Large	116	$66.4	$1,184	$0.6	$17.1
Private[f]	Small	138	$21.2	$488	$0.2	$6.9
	Large	759	$1,180.6	$1,920	$1.5	$40.4

Table 9-4: Compliance Costs for Electric Generators by Ownership Type and Size ($2010)

Ownership Type	Entity Size	Number of Plants (weighted)[a,b]	Total Annualized Pre-Tax Compliance Costs (Millions)[a,b]	Average Annualized Pre-tax Compliance Cost per MW of Capacity[c]	Average Annualized Pre-tax Compliance Cost per Plant (Millions)[d]	Maximum Annualized Pre-tax Compliance Cost per Plant (Millions)[e]
All Plants[g]		**1,079**	**$1,323.2**	**$1,767**	**$1.2**	**$40.4**
Option 5						
Government (excl. federal)	Small	51	$17.9	$2,553	$0.3	$6.9
	Large	116	$111.1	$1,981	$1.0	$30.3
Private[f]	Small	138	$48.2	$1,109	$0.3	$19.4
	Large	759	$1,908.4	$3,104	$2.5	$128.3
All Plants[g]		**1,079**	**$2,209.4**	**$2,950**	**$2.0**	**$128.3**

a. Four plants are owned by multiple private entities of different size; to assign a unique entity size to these plants, EPA assumed each plant to be owned by a small private entity. One plant is owned by two entities with equal shares of ownership - a small municipality and a large cooperative; to assign unique ownership type and entity size to this plant, EPA assumed this plant to be owned by a small municipality. Another plant is owned by a large municipality and a large investor-owned utility with equal shares of ownership; to assign unique ownership type and entity size to this plant, EPA assumed this plant to be owned by a large municipality. For plants owned by multiple entities with equal ownership shares and in different ownership and/or size categories, EPA assigned plant-level compliances costs to appropriate ownership and size categories in accordance with plant ownership shares.
b. Plant counts and cost values are sample weighted estimates.
c. Average cost per MW values were calculated using total compliance costs and capacity for all steam electric 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.
d. Average cost per plant values were calculated using total number of steam electric plants owned by entities in a given ownership category.
e. Values reflect maximum of un-weighted costs to surveyed plants only.
f. Plant counts and cost estimates reported for the *Private* sector include 67 plants owned by 30 rural electric cooperatives (13 small and 17 large entities) and costs estimated for these plants. For entity size determination see *Chapter 8*.
g. Plant counts and cost estimates reported for *All Plants* include 15 federal government-owned plants and costs estimated for these plants. As discussed in *Chapter 8*, all federal parent entities are considered large.
Source: U.S. EPA analysis, 2013

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 $158 million under Option 3a to $1,957 million under Option 5, with a maximum of $292 million and $4,189 million in 2020 under Options 1 and 5, respectively. Impacts of the other three preferred options (along with Option 3a) fall within this range: under Option 3b, the Agency expects total annualized pre-tax compliance costs to be $215 million, with a maximum of $614 million in 2020; under Option 3, the Agency expects total annualized pre-tax compliance costs to be $470 million, with a maximum of $1,041 million in 2020; finally, under Option 4b, the annualized pre-tax compliance costs are $830 million, with a maximum of $1,944 million in 2020.

9.4 UMRA Analysis Summary

EPA estimates that each of the four preferred options for existing sources (Options 3a, 3b, 3 and 4a) would result in expenditures of at least $100 million for State and local government entities, in the aggregate, or for the private sector in any one year. *Table 9-5* presents a summary of compliance costs for publicly- and privately-owned entities to implement this rule for each regulatory option. As discussed earlier, the proposed ELGs would result in minimal changes in the reporting and recordkeeping requirements currently in effect for steam electric dischargers (e.g., some steam electric 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 proposed ELGs.

Total annualized compliance costs to government entities range from approximately $7 million under Option 3a to $129 million under Option 5, with the maximum compliance cost in any one year ranging from $14 million to $406 million in 2019 under Options 3a and 5, respectively. Private entities are projected to incur annualized compliance costs ranging from $158 million under Option 3a to $1,957 million under Option 5, with a maximum of $292 million and $4,189 million in 2020 under Options 3a and 5, respectively.

Under Option 3b, EPA estimates total annualized compliance costs for government entities to be approximately $10 million, with a maximum of $32 million in 2018 and for private entities to be $215 million, with a maximum of $614 million in 2020. Under Option 3, EPA estimates total annualized compliance costs for government entities to be approximately $31 million, with a maximum of $110 million in 2019 and for private entities to be $470 million, with a maximum of $1,041 million in 2020. Finally, for Option 4a, government entities are estimated to incur annualized costs of approximately $41 million, with maximum costs of $142 million in 2018; private entities are estimated to incur annualized costs of approximately $830 million, with maximum costs of $1,944 million in 2020.

Note that the timing of when the maximum cost occurs is driven by the modeled technology implementation schedule tied to 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.

Table 9-5: Summary of UMRA Costs (Millions; $2010)[a]

Sector Incurring Costs[b]	Annualized Compliance Cost[c] — Total Cost	Annualized Compliance Cost[c] — Maximum One-Year Cost
Option 3a		
Government (excl. federal)	$6.6	$13.8
Private	$158.0	$291.5
Option 3b		
Government (excl. federal)	$10.0	$31.9
Private	$215.0	$614.0
Option 1		
Government (excl. federal)	$15.5	$58.2
Private	$209.5	$493.5
Option 2		
Government (excl. federal)	$24.7	$95.6
Private	$312.3	$749.4
Option 3		
Government (excl. federal)	$31.2	$109.5
Private	$470.2	$1,040.9
Option 4a		
Government (excl. federal)	$40.9	$141.8
Private	$829.9	$1,943.7
Option 4		
Government (excl. federal)	$77.0	$244.2
Private	$1,201.8	$2,688.7

Table 9-5: Summary of UMRA Costs (Millions; $2010)[a]

Sector Incurring Costs[b]	Annualized Compliance Cost[c]	
	Total Cost	Maximum One-Year Cost
Option 5		
Government (excl. federal)	$128.9	$406.2
Private	$1,956.6	$4,189.1

a. Steam electric plants are not expected to incur any additional administrative costs to implement and NPDES permitting authorities are not expected to incur significant additional costs to administer the proposed ELGs.
b. For this analysis, the private sector includes rural electric cooperatives.
c. For plants owned by multiple entities with equal ownership shares and in different ownership and/or size categories, EPA assigned plant-level compliances costs to appropriate ownership and size categories in accordance with plant ownership shares. Cost values are sample weighted estimates.
Source: U.S. EPA analysis, 2013

10 Other Administrative Requirements

This chapter presents analyses conducted in support of the proposed ELGs to address the requirements of Executive Orders and Acts applicable to this regulation. These analyses complement EPA‟s assessment of the compliance costs, economic impacts, and economic achievability of the proposed 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 proposed 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, 2013b; DCN SE03172).

As detailed in earlier chapters of this report, EPA also assessed the impacts of the proposed 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 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 Executive Order 12898, EPA examined whether the proposed ELGs would have potential EJ concerns in the geographic areas affected by steam electric plant discharges. Benefits from the proposed ELGs may be differentially distributed among population subgroups depending on a variety of factors, including proximity to affected waters, unique exposure pathways, cumulative risk exposure, and susceptibility to environmental risk. For example, subsistence fishers rely on self-caught fish for a larger share of their food intake than the general population, and as such may incur a larger share of benefits arising from the proposed ELGs.

To address the EJ implications of the proposed ELGs, EPA analyzed the demographic characteristics of the populations currently exposed to these discharges through consuming self-caught fish from receiving reaches (i.e., populations located within 100 miles of the affected reaches,[106] also referred to as the "benefit regions" in the rest of this discussion) to determine whether minority and/or low-income populations incur disproportionally high environmental impacts or are disproportionally excluded from realizing the benefits of this proposed regulation. EPA also evaluated the share of human health benefits (from fish consumption) that accrue to subsistence fishers versus recreational anglers.

The following two sections describe 1) a comparison of the socio-demographic characteristics of the populations expected to accrue benefits as a result of the proposed ELGs to state and national averages, and 2) the evaluation of the share of human health benefits that accrue to subsistence fishers versus recreational anglers.

10.2.1 Socio-demographic Characteristics of Affected Populations

EPA assessed the demographic characteristics of the populations within benefit regions. EPA collected population-specific Census data on:

- the median household income,
- the percent of the population below the poverty threshold, and
- the percent of the population that is minority.

EPA used these demographic metrics as indicators of communities where EJ concerns may exist, comparing them to state and national averages. EJ concerns may exist in areas where the percent of the population below the poverty threshold is higher than the state or national average, the median household income is below the

[106] As detailed in the *Benefit and Cost Analysis for Proposed Steam Electric Effluent Limitations Guidelines Regulation* document (BCA; EPA, 2012d), EPA used a distance of 100 miles to determine the affected population, based on Viscusi, Huber, and Bell (2008) who found that 78 percent of anglers live within 100 miles of their fishing destinations.

state or national average, or the percent of the population that is minority is above the state or national average.

This analysis focuses on the spatial distribution of minority and low-income groups to determine whether these groups are more or less represented in the populations expected to benefit from the proposed ELGs. If the population within a benefit region has a larger proportion of minority or low-income families than the state average, it may indicate that the proposed ELGs would disproportionately benefit communities where EJ concerns exist, an effect that would not raise EJ concerns. In contrast, if the benefit region has a smaller share of minority or low-income families than the state average, then communities where EJ concerns exist may be disproportionately precluded from the benefits, an effect that would raise EJ concern.

EPA used the U.S. Census Bureau"s American Community Survey (ACS) data for 2006 to 2010 to identify the median household income (Table B19013) and poverty status (Table C17002) at the state and census block levels. EPA also used 2010 U.S. Census data (Summary File 1; Table 8 – P3) to identify the percent of the population that is minority at the census block and state levels. EPA overlaid the data with GIS data of the 100-mile buffer zones surrounding receiving reaches to characterize the demographic characteristics of the affected communities living within each of 344 discrete benefit regions.

Many of the benefit regions span more than one state. As such, to compare the characteristics of these affected communities to state-level averages, EPA calculated state weighted averages according to the spatial extent of the benefit region (i.e. the 100-mile buffer surrounding the receiving reach). For example, if a buffer zone surrounding a reach is 35 percent in Illinois and 65 percent in Indiana, the weighted average state median household income for population in that benefit region would be calculated as:

$$(MHI_{(Indiana)} * 0.65) + (MHI_{(Illinois)} * 0.35)$$

EPA compared the demographic characteristics of the affected communities to national and state averages. Approximately 14 percent of households in the 344 affected communities EPA identified in this analysis are below the poverty threshold, which is the same as the national average. Twenty-five percent of households in affected communities are minority, compared with a national average of 36 percent. Additionally, the median household income in affected communities is $48,579, while it is $51,914 nationally. In sum, the affected populations are similar to the nation in terms of households living below the poverty line and have a smaller share of minority households. The median household income in affected communities is less than the national average.

For comparisons to the state averages, EPA compared each affected population to its corresponding state average and then counted the number of those populations with results that indicate a potential EJ concern. *Table 10-1* shows the results of this approach. Compared with state averages, 26 percent of affected communities have a higher percentage of households below the poverty threshold, 54 percent have a lower median household income, and 47 percent have a higher percent of the population that is minority.

Table 10-1: Socio-demographic Characteristics of Affected Communities, Compared to State Average

Metric Indicating Potential EJ Concern	Number of Affected Communities[a]	Percent of Affected Communities[b]
"Percent of Households Below Poverty Threshold" Higher than State Average	88	26%
"Median Household Income" Less than State Average	187	54%

Table 10-1: Socio-demographic Characteristics of Affected Communities, Compared to State Average

Metric Indicating Potential EJ Concern	Number of Affected Communities[a]	Percent of Affected Communities[b]
"Percent of the Population that is Minority" Higher than State Average	161	47%

a. "Affected communities" are communities living within 100 miles of the receiving reach.
b. Calculated that the number of affected communities divided by 344 total affected communities. Percentages do not sum to 100 percent since many affected communities have more than one metric indicating potential EJ concern.

Of the 344 affected communities, 28 (8 percent) may have EJ concerns under all three metrics, 79 (23 percent) under two metrics, and 194 (56 percent) under one metric. Forty-three (13 percent) affected communities would not be considered has having EJ concerns under any of the metrics. Approximately 88 percent of communities that are expected to benefit from the proposed ELGs have potential EJ concerns according to at least one of the metrics. Although the specific characteristics of households that would benefit from the proposed ELGs are not known, these results suggest that minority and low-income communities would not be precluded from receiving the benefits of the proposed ELGs.

Table 10-2: Affected Communities[a] with Potential EJ Concerns

Number of Metrics Indicating EJ Concerns[b]	Number of Affected Communities	Percent of Affected Communities	Cumulative Percent of Affected Communities
Three	28	8%	8%
Two	79	23%	31%
One	194	56%	88%
Zero	43	13%	100%
Total	344	100%	100%

a. "Affected communities" are communities living within 100 miles of a steam electric plant receiving reach.
b. The metrics indicating potential EJ concern include: 1) "percent of households below poverty threshold" higher than the state average, 2) "median household income" lower than state average, and 3) "percent of the population that is minority" higher than the state average.

10.2.2 Benefits to Subsistence Fishers

In its analysis of health benefits (see U.S. EPA, 2013b; DCN SE03172), EPA assumed for this analysis that 5 percent of the exposed population is subsistence fishers, and that the remaining 95 percent is recreational anglers. This is based on the assumed 95th percentile fish consumption rate for subsistence fishers. These individuals consume more self-caught fish than recreational anglers and as such would be expected to experience higher health risks associated with steam electric pollutants in fish tissue.

Table 10-3 shows the annual human health benefits for two of the regulatory options (Options 3 and 4) disaggregated into benefits accruing to recreational anglers and subsistence fishers. Although in each case, subsistence fishers account for 5 percent of the exposed population, they account for 18 percent to 50 percent of the total benefits. EPA expects these results to be illustrative of the potential distribution of benefits for the four preferred options (Options 3a, 3b, 3 and 4a). Disproportionate impacts on subsistence fishers could indicate EJ concerns; these results show that the proposed ELGs will not preclude these communities from receiving benefits.

Table 10-3. Annualized Health Benefits to Recreational Anglers and Subsistence Fishers, Option 3 (Millions; 2010$)

ELG Regulatory Option	Discount Rate	Benefit Category	Recreational Anglers			Subsistence Fishers			Total Exposed Population	
			Annual Benefits		% of Total	Annual Benefits		% of Total	Annual Benefits	
			Low	High		Low	High		Low	High
Option 3	3 percent	Avoided Cancer Cases from Exposure to Arsenic	$0.08		81%	$0.02		19%	$0.09	
		Avoided IQ Losses from Exposure to Lead	$1.79	$2.56	81%	$0.42	$0.60	19%	$2.21	$3.17
		Avoided Compensatory Education from Exposure to Lead	$0.01		50%	$0.01		50%	$0.02	
		Avoided IQ Losses from in-Utero Exposure to Mercury	$3.28	$4.70	81%	$0.79	$1.14	19%	$4.08	$5.83
	7 percent	Avoided Cancer Cases from Exposure to Arsenic	$0.04		81%	$0.01		19%	$0.05	
		Avoided IQ Losses from Exposure to Lead	$0.13	$0.25	81%	$0.03	$0.06	19%	$0.16	$0.31
		Avoided Compensatory Education from Exposure to Lead	$0.01		50%	$0.01		50%	$0.01	
		Avoided IQ Losses from in-Utero Exposure to Mercury	$0.24	$0.48	81%	$0.06	$0.12	19%	$0.30	$0.59
Option 4	3 percent	Avoided Cancer Cases from Exposure to Arsenic	$0.13		50%	$0.13		50%	$0.25	
		Avoided IQ Losses from Exposure to Lead	$4.53	$6.48	82%	$1.02	$1.46	18%	$5.55	$7.94
		Avoided Compensatory Education from Exposure to Lead	$0.05		70%	$0.02		30%	$0.07	
		Avoided IQ Losses from in-Utero Exposure to Mercury	$6.78	$9.70	81%	$1.64	$2.35	19%	$8.42	$12.05
	7 percent	Avoided Cancer Cases from Exposure to Arsenic	$0.07		50%	$0.07		50%	$0.14	
		Avoided IQ Losses from Exposure to Lead	$0.33	$0.65	82%	$0.07	$0.15	18%	$0.40	$0.80
		Avoided Compensatory Education from Exposure to Lead	$0.02		71%	$0.01		29%	$0.03	
		Avoided IQ Losses from in-Utero Exposure to Mercury	$0.49	$0.98	81%	$0.12	$0.24	19%	$0.61	$1.21

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 proposed ELGs are an economically significant regulation as defined under Executive Order 12866. However, the environmental health risks or safety risks addressed by this action do not present a disproportionate risk to children, and, as detailed in the *Benefit and Cost Analysis for Proposed Steam Electric Effluent Limitations Guidelines Regulation* document (BCA; U.S. EPA, 2013b; DCN SE03172), EPA identified several ways in which the proposed ELGs would benefit children, including by reducing health risk from exposure to pollutants present in steam electric plant discharges. These benefits are summarized below.

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 two of the regulatory options (Options 3 and 4). EPA estimated that the proposed ELGs would reduce lead exposure (from fish consumption) for 12,478 children annually, and would reduce mercury exposure (from maternal fish consumption) for 1,932 babies born annually. EPA estimated the annual benefits of avoided IQ loss from children lead exposure under Option 3 that range between $2.2 million and $3.2 million using a 3 percent discount rate (0.2 million to $0.3 million annually using a 7 percent discount rate). Annual benefits of avoided IQ losses from *in-utero* mercury exposure for Option 3 range from $4.1 million to $5.8 million using a 3 percent discount rate ($0.3 million to $0.6 million using a 7 percent discount rate). As discussed in the BCA, EPA did not estimate this category of benefits for the other three preferred options (Options 3a, 3b and 4a). However, EPA expects the benefits of Options 3a and 3b to be smaller than those of Option 3. Further, EPA estimated the benefits of Option 4, which provides an upper bound estimate of the benefits of Option 4a (i.e., benefits of Option 4a are between those of Options 3 and 4). As discussed in the BCA, Option 4 has annual benefits from avoided IQ losses from lead exposure estimated at $5.6 million to $7.9 million, using a 3 percent discount rate ($0.4 million to $0.8 million annually using a 7 percent discount rate), plus annual benefits from avoided IQ losses from *in-utero* mercury exposure ranging between $8.4 million and $12.1 million using a 3 percent discount rate ($0.6 million to $1.2 million using a 7 percent discount rate).

Also, children with very high blood lead concentrations and IQs less than 70 may require compensatory education tailored to their specific needs. EPA estimated that the number of children in the affected population with very high blood lead concentrations (above 20 ug/dL) and IQs less than 70 would be reduced from 15 to 11 (between 2017 and 2040) under Option 3, for annual benefits of $0.02 million using a 3 percent discount rate ($0.01 million using a 7 percent discount rate). As discussed above, EPA did not estimate the benefits of Options 3a, 3b and 4a, but the benefits of Options 3 and 4 provide the lower and upper bounds, respectively, of Option 4a benefits. Thus, Option 4 would further reduce the number of children in this category to less than 3 children over the period of 2017 through 2040, for annual benefits valued at $0.07 million per year using a 3 percent discount rate ($0.03 million using a 7 percent discount rate).

Additional benefits to children from reduced exposure to steam electric pollutant discharges were not quantified in the analysis 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 proposed 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 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 $13.8 million under Option 3a to $406.2 million under Option 5 (see *Chapter 9: Unfunded Mandates Reform Act (UMRA)* for details). The four preferred regulatory options have maximum costs in any one year to governments of $13.8 million, $31.9 million, $109.5 million, and $141.8 million, respectively for Options 3a, 3b, 3 and 4a. 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 proposed action to permit them to have meaningful and timely input into its development. The preamble to this regulation describes these consultations.

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 proposed 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 proposed 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.” [107] Those criteria include:

- Reductions in crude oil supply in excess of 10,000 barrels per day;
- Reductions in fuel production in excess of 4,000 barrels per day;
- Reductions in coal production in excess of 5 million tons per year;
- Reductions in natural gas production in excess of 25 million mcf per year;
- Reductions in electricity production in excess of 1 billion kilowatt-hours per year, or in excess of 500 megawatts of installed capacity;
- 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 proposed ELGs. Through increases in the cost of generating electricity and shifts in the types of generators employed, the proposed 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 3 and 4) to analyze the proposed ELGs for each of these potential effects (see *Chapter 5: Electricity Market Analyses*). As discussed in *Chapter 5*, the results provide insight on the impacts not only of Option 3 and 4, but also the other three preferred regulatory options; Options 3a and 3b are expected to have smaller

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

impacts than Option 3, whereas the impacts of Option 4a are expected to fall between those of Options 3 and 4.

10.6.1 Impact on Electricity Generation

The electricity market analyses (*Chapter 5*) estimate in the aggregate, that the electricity market would generate 286 million kWh less electricity in 2020 (technology implementation year; short run) and 62 million kWh less electricity in 2030 (the steady-state post-compliance year; long run) under Option 3 than it would in the baseline case. Option 4 results in 884 million kWh less electricity in 2020 and 81 million kWh less electricity in 2030. Under either option and in both the short and long run, the effect of the proposed ELGs is less than the 1 billion kWh reduction required for the regulation to be considered a significant energy action. Although generation from the affected steam electric plants may be reduced more substantially, relative to baseline steam generation, EPA recognizes that this reduction is offset by increased production from other plants, resulting in a small net decrease in overall production.

10.6.2 Impact on Electricity Generating Capacity

Based on the electricity market analyses, few if any generating units are expected to retire as the result of the proposed ELGs, depending on the options; additionally, neither of the two options analyzed by EPA is expected to result in full plant closures. In fact, Option 3 results in *avoided* steam electric capacity closures of 102 MW.[108] Option 4 results in the closure of 14 generating steam electric units (1,125 MW) and the avoided closure of 5 other generating units (808 MW), leading to an estimated net closure of nine generating units (317 MW). All 14 units that are projected to close are located within six plants that otherwise remain open. Consequently, EPA does not believe that the proposed ELGs constitute a “significant energy action” in terms of estimated potential effects on electric generating capacity.

10.6.3 Cost of Energy Production

The proposed ELGs 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 3 would increase by 0.4 percent. Under Option 4, the total electricity generation costs are expected to increase by 1.1 percent in 2020 and 0.9 percent in 2030, relative to baseline. At the regional level, the increase in electricity generation costs varies, ranging from 0.1 percent in WECC and NPCC and 0.6 to 0.7 percent in SERC in the short run and in the long run under Option 3. Option 4 shows cost increases ranging between 0.3 percent (in WECC) and 1.7 percent (in RFC) in 2020, and between 0.2 percent (in FRCC and NPCC) and 1.5 percent (in RFC) in 2030. Consequently, no region would experience energy price increases of more than 2 percent as a result of the proposed ELGs in either the short or the long run.

10.6.4 Dependence on Foreign Supply of Energy

EPA‟s electricity market analyses did not support explicit consideration of the effects of the proposed ELGs on foreign imports of energy. However, the proposed ELGs directly affect electric power plants, which are generally not subject to 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.

108 Avoided capacity closures occur when one or more generating units that are otherwise projected to cease operations in the baseline become more economically attractive sources of electricity in the post-compliance case, because of relative changes in the economics of electricity production across the full market, and thus avoid closure.

As presented in *Table 10-4,* under Option 3, coal-based electricity generation along with coal consumption is expected to decline by less than 0.1 percent; under Option 4 (*Table 10-5*), the decline is expected to be 0.3 percent. Generation using other fuels – biomass, landfill gas, natural gas, nuclear power, oil, and wind power – and consequently, consumption of those fuels is expected to increase, however modestly. The largest increase in fuel use is a 0.4 percent increase in natural gas use under Option 4.

Given the very small increases in usage of fuel other than coal, it is reasonable to assume that the increase in demand for these fuels 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 proposed ELGs would not significantly increase dependence on foreign supplies of energy under any of the preferred regulatory options for existing sources.

Table 10-4: Total Market-Level Capacity, Generation, and Fuel Use by Fuel Type for Option 3[a]

	Generating Capacity (MW)			Electricity Generation (GWh)			Fuel Consumption (TBtu)		
Fuel Type	**Baseline**	**Option 3**	**% Change**	**Baseline**	**Option 3**	**% Change**	**Baseline**	**Option 3**	**% Change**
Biomass	7,313	7,325	0.2%	52,073	52,166	0.2%	574	575	0.2%
Coal	301,207	301,211	0.0%	2,043,801	2,042,095	-0.1%	20,999	20,980	-0.1%
Fossil Waste[b]	872	872	0.0%	2,062	2,062	0.0%	18	18	0.0%
Geothermal	3,466	3,466	0.0%	23,961	23,961	0.0%	585	585	0.0%
Hydro	98,816	98,816	0.0%	286,396	286,433	0.0%	0	0	NA
Landfill Gas	4,505	4,515	0.2%	32,636	32,711	0.2%	445	446	0.2%
MSW	2,133	2,133	0.0%	14,392	14,392	0.0%	228	228	0.0%
Natural Gas[c]	476,869	476,430	-0.1%	1,191,096	1,191,594	0.0%	8,730	8,733	0.0%
Non-Fossil	1,026	1,026	0.0%	5,852	5,852	0.0%	55	55	0.0%
Nuclear	103,155	103,155	0.0%	819,308	820,230	0.1%	8,592	8,601	0.1%
Oil	37,841	38,764	2.4%	179	180	0.8%	2	2	0.9%
Pet. Coke	2,677	2,677	0.0%	18,980	18,980	0.0%	187	187	0.0%
Solar	1,332	1,332	0.0%	2,733	2,733	0.0%	0	0	NA
Waste Coal	2,120	2,120	0.0%	15,612	15,612	0.0%	165	165	0.0%
Wind	62,779	62,785	0.0%	192,838	192,854	0.0%	0	0	NA
Total	**1,106,110**	**1,106,627**	**0.0%**	**4,701,917**	**4,701,855**	**0.0%**	**40,580**	**40,575**	**0.0%**

a. Numbers may not add up due to rounding.

b. Includes 250 MW of imported capacity and 894 GWh of imported electricity from Canada and Mexico.

c. Reduction in natural gas-fueled capacity is the result of (1) 4 oil and gas steam units (442 MW) and 1 combustion turbine unit (62 MW) switching fuel from natural gas to oil and (2) increase in natural gas-fueled new capacity additions (65 MW).

Table 10-5: Total Market-Level Capacity, Generation, and Fuel Use by Fuel Type for Option 4[a]

	Generating Capacity (MW)			Electricity Generation (GWh)			Fuel Consumption (TBtu)		
Fuel Type	**Baseline**	**Option 4**	**% Change**	**Baseline**	**Option 4**	**% Change**	**Baseline**	**Option 4**	**% Change**
Biomass	7,313	7,337	0.3%	52,073	52,248	0.3%	574	576	0.3%
Coal	301,207	300,368	-0.3%	2,043,801	2,037,672	-0.3%	20,999	20,927	-0.3%
Fossil Waste[b]	872	872	0.0%	2,062	2,062	0.0%	18	18	0.0%
Geothermal	3,466	3,466	0.0%	23,961	23,961	0.0%	585	585	0.0%
Hydro	98,816	98,816	0.0%	286,396	286,415	0.0%	0	0	NA
Landfill Gas	4,505	4,506	0.0%	32,636	32,640	0.0%	445	445	0.0%
MSW	2,133	2,133	0.0%	14,392	14,392	0.0%	228	228	0.0%
Natural Gas	476,869	477,188	0.1%	1,191,096	1,195,792	0.4%	8,730	8,766	0.4%
Non-Fossil	1,026	1,026	0.0%	5,852	5,852	0.0%	55	55	0.0%
Nuclear	103,155	103,155	0.0%	819,308	820,230	0.1%	8,592	8,601	0.1%
Oil	37,841	38,702	2.3%	179	178	-0.4%	2	2	-0.4%
Pet. Coke	2,677	2,677	0.0%	18,980	18,980	0.0%	187	187	0.0%
Solar	1,332	1,332	0.0%	2,733	2,733	0.0%	0	0	NA
Waste Coal	2,120	2,120	0.0%	15,612	15,612	0.0%	165	165	0.0%

Table 10-5: Total Market-Level Capacity, Generation, and Fuel Use by Fuel Type for Option 4[a]

	Generating Capacity (MW)			Electricity Generation (GWh)			Fuel Consumption (TBtu)		
Fuel Type	**Baseline**	**Option 4**	**% Change**	**Baseline**	**Option 4**	**% Change**	**Baseline**	**Option 4**	**% Change**
Wind	62,779	62,870	0.1%	192,838	193,070	0.1%	0	0	NA
Total	**1,106,110**	**1,106,566**	**0.0%**	**4,701,917**	**4,701,836**	**0.0%**	**40,580**	**40,556**	**-0.1%**

a. Numbers may not add up due to rounding.

b. Includes 250 MW of imported capacity and 894 GWh of imported electricity from Canada and Mexico.

10.6.5 Overall E.O. 13211 Finding

From these analyses, EPA concludes that the proposed 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 proposed 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 discussed in *Chapter 5* and above, the results for Options 3 and 4 provide insight on the impacts of all four preferred regulatory options; Options 3a and 3b are expected to have smaller impacts than Option 3 (also a preferred option), whereas the impacts of Option 4a are expected to fall between those of Options 3 and 4. As a result, EPA did not prepare a Statement of Energy Effects. For more detail on effects of the proposed 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.[109]

The proposed 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 proposed ELGs (see *Chapter 3: Compliance Costs*). However, plants would also realize savings by no longer monitoring effluent that would no longer occur under the proposed ELGs. The net effects of the changes in monitoring and reporting are expected to be minimal.

Further, EPA does not believe that the proposed rule would lead to additional costs to permitting authorities. The proposed rule would not change permit application requirements or the associated review, it would not increase the number of permits issued to steam electric plants, and nor 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. Permitting authorities establishing site specific requirements spend significant effort and resources. Establishing nationally applicable BAT requirements that eliminate the need to develop BPJ-based limitations would make permitting easier and less costly in this respect. 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 today‟s proposal.

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 proposed ELGs do not involve technical standards, for example in the measurement of pollutant loads. Nothing in the proposed 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.

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

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B Sensitivity Analyses of Selected BAT and PSES Options

As discussed in this document, EPA conducted sensitivity analyses of two of the eight regulatory options for existing sources (Options 3 and 4) to assess the effects of alternative applicability and compliance schedule provisions of the proposed ELGs and assumptions on the cost and economic impact analyses. The Agency assessed the following sensitivity scenarios:

- *Sensitivity Scenario 1: Future Profile of Steam Electric Plant Universe ("Future-a" and "Future-b")*: The analyses and the conclusions on economic achievability presented in this report reflect consideration of wastestreams generated by air pollution controls that will likely be in operation at plants at the time of ELG promulgation, i.e., by 2014. However, EPA recognizes that some recently promulgated Clean Air Act requirements may lead to additional air pollution controls (and resulting wastestreams) at existing plants beyond the date of ELG promulgation. In an effort to confirm that proposed ELG requirements would be economically achievable in such cases, EPA also conducted a sensitivity analysis that forecasts future installations of air controls through 2020[110] and the associated costs of complying with the proposed ELGs for the wastewater that may result from the forecasted air control installations. EPA used two primary data sources to assess future air control installations: the 2010 Questionnaire for the Steam Electric Power Generating Effluent Guidelines (industry survey; U.S. EPA, 2010a) and the Integrated Planning Model (IPM).[111] The Agency conducted this sensitivity analysis in two ways: (a) relying solely on the information obtained from IPM (*Sensitivity Scenario Future-a*) and (b) relying on information obtained from both IPM and the industry survey (*Sensitivity Scenario Future-b*). After making these adjustments, the Agency identified 1,084 steam electric plants under either of the Sensitivity Scenarios (1a or 1b); consequently, these sensitivity analyses were conducted for these 1,084 plants. EPA developed future profile costs for Option 4 assuming that wastestreams from any new FGD system forecast to be installed at existing plants would be treated using a separate biological treatment system, even where a plant otherwise could treat leachate and FGD wastestreams combined.
- *Sensitivity Scenario 2: All Steam Electric Units ("All Units")*: To assess the effects of establishing separate requirements for oil-fired generating units and small units with generating capacity of 50 MW or less, EPA also conducted a sensitivity analysis for Options 3 and 4 absent of this differentiation. The Agency conducted this sensitivity analysis for the 1,079 steam electric plants analyzed for the proposed Options 3 and 4.
- *Sensitivity Scenario 3: Control Technology Implementation in 2014-2018 ("Immediate")*: To assess the sensitivity of cost and economic impact analysis results to the assumed control technology implementation timeframe, EPA analyzed proposed Options 3 and 4 assuming that steam electric plants would implement control technologies immediately upon renewal of their NPDES permit post-promulgation, instead of three years following renewal of their permit post-promulgation. This results in an assumed technology implementation window of calendar years 2014 through 2018 instead of calendar years 2017 through 2021. The Agency conducted this sensitivity analysis for the 1,079 steam electric plants analyzed for the proposed Options 3and 4.

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110 EPA expects that plants will be in compliance with new federal and state air pollution control requirements by 2020.

111 EPA used the Integrated Planning Model (IPM®), a comprehensive electricity market optimization model, to evaluate regulatory impacts of the proposed ELG within the context of regional and national electricity markets. For more information on this analysis and IPM, see *Chapter 5: Electricity Market Analyses* and *Appendix C: IPM*.

- *Sensitivity Scenario 4: Fifty-Percent Cost-Pass-Through ("50-50 CPT")*: To assess the sensitivity of analysis results to the cost pass-through assumption, EPA analyzed Options 3 and 4 assuming that steam electric plants will be able to pass through 50 percent of their compliance costs to consumers through higher electricity rates. As discussed in *Chapter 4: Economic Impact Screening Analyses*, this alternative cost pass-through is illustrative only; it is used to highlight the sensitivity of the results to this assumption. The Agency conducted this sensitivity analysis for the 1,079 steam electric plants analyzed for the proposed Options 3 and 4.

Tables in this Appendix present results of these sensitivity analyses; for comparison, the tables include results for the main analysis of proposed Options 3 and 4.

Table B-1: Annualized Compliance Costs for Options 3 and 4 by Sensitivity Scenario (in millions, $2010, at 2014)[a,b]

Sensitivity Scenario	Pre-Tax Compliance Costs				After-Tax Compliance Costs			
	Capital Technology	Other Initial One-Time[b]	Total O&M	Total	Capital Technology	Other Initial One-Time[b]	Total O&M	Total
Option 3								
Proposed Option[c]	**$209.6**	**$0.0**	**$351.8**	**$561.4**	**$147.9**	**$0.0**	**$241.0**	**$389.0**
Future-a[d]	$228.7	$0.0	$374.0	$602.7	$160.4	$0.0	$255.1	$415.5
Future-b[d]	$234.7	$0.0	$380.5	$615.2	$164.4	$0.0	$259.5	$423.9
All Units[c]	$211.9	$0.0	$354.7	$566.6	$149.7	$0.0	$243.2	$392.9
Immediate[c]	$247.2	$0.0	$414.9	$662.1	$174.5	$0.0	$284.3	$458.8
Option 4								
Proposed Option[c]	**$568.5**	**$0.0**	**$804.7**	**$1,373.2**	**$382.2**	**$0.0**	**$534.6**	**$916.9**
Future-a[d]	$587.7	$0.0	$826.9	$1,414.6	$394.7	$0.0	$548.7	$943.5
Future-b[d]	$593.7	$0.0	$833.4	$1,427.1	$398.8	$0.0	$553.1	$951.8
All Units[c]	$583.1	$0.0	$829.2	$1,412.4	$394.0	$0.0	$554.9	$948.9
Immediate[c]	$670.7	$0.0	$949.3	$1,620.1	$451.0	$0.0	$630.7	$1,081.7

a. See *Chapter 3* for a detailed discussion of the methodology used to conduct this analysis.
b. The change in the cost-pass-through assumption is irrelevant for this analysis. Consequently, EPA did not conduct analysis of Sensitivity Scenario 4: Fifty-Percent Cost-Pass-Through.
c. Cost estimates are for 1,079 plants analyzed for the proposed Options 3 and 4.
d. Cost estimates are for 1,084 plants analyzed under this sensitivity scenario.
Source: U.S. EPA Analysis, 2013

Table B-2: Plant-Level Cost-to-Revenue Analysis Results for Options 3 and 4 by Sensitivity Scenario[a]

Sensitivity Scenario	Total Number of Plants	No Revenue[b]	Number of Plants with a Cost-to-Revenue Ratio of			
			0%[c]	≠0 and <1%	≥1 and <3%	≥3%
Option 3						
Proposed Option	**1,079**	**5**	**920**	**102**	**38**	**14**
Future-a	1,084	9	909	109	41	16
Future-b	1,084	9	909	109	41	16
All Units	1,079	5	906	108	40	20
Immediate	1,079	5	920	102	38	14
50-50 CPT	1,079	5	920	131	20	3
Option 4						
Proposed Option	**1,079**	**5**	**798**	**111**	**117**	**48**
Future-a	1,084	9	795	110	120	50
Future-b	1,084	9	795	110	120	50
All Units	1,079	5	778	116	116	64
Immediate	1,079	5	798	111	117	48
50-50 CPT	1,079	5	798	199	67	10

Table B-2: Plant-Level Cost-to-Revenue Analysis Results for Options 3 and 4 by Sensitivity Scenario[a]

Sensitivity Scenario	Total Number of Plants	No Revenue[b]	Number of Plants with a Cost-to-Revenue Ratio of			
			0%[c]	≠0 and <1%	≥1 and <3%	≥3%

a. See *Chapter 4* for a detailed discussion of the methodology used to conduct this analysis.
b. EPA was not able to estimate revenue for 5 plants (9 plants included in the future profile of steam electric plant universe).
c. 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, 2013

Table B-3: Entity-Level Cost-to-Revenue Analysis Results for Options 3 and 4 by Sensitivity Scenario[a]

Sensitivity Scenario	Case 1: Lower bound estimate of number of entities owning steam electric plants						Case 2: Upper bound estimate of number of entities owning steam electric 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[c]		0%[b]	≠0 and <1%	≥1 and <3%	≥3%	Unknown[c]
Option 3												
Proposed Option[d]	**243**	**168**	**49**	**7**	**5**	**14**	**507**	**416**	**49**	**7**	**5**	**30**
Future-a[e]	246	163	53	8	6	16	510	411	53	8	6	32
Future-b[e]	246	163	53	8	6	16	510	411	53	8	6	32
All Units[d]	243	160	57	7	5	14	507	406	59	7	5	30
Immediate[d]	243	168	49	7	5	14	507	416	49	7	5	30
50-50 CPT[d]	243	168	49	7	5	14	507	416	49	7	5	30
Option 4												
Proposed Option[d]	**243**	**137**	**64**	**21**	**7**	**14**	**507**	**385**	**64**	**21**	**7**	**30**
Future-a[e]	246	136	65	20	9	16	510	384	65	20	9	32
Future-b[e]	246	136	65	20	9	16	510	384	65	20	9	32
All Units[d]	243	128	67	23	11	14	507	373	70	23	11	30
Immediate[d]	243	137	64	21	7	14	507	385	64	21	7	30
50-50 CPT[d]	243	137	64	21	7	14	507	385	64	21	7	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 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.
c. EPA was unable to determine revenues for 1federal parent entity.
d. Analysis conducted for 1,079 plants analyzed for the proposed Options 3 and 4.
e. Analysis conducted for 1,084 plants analyzed under this sensitivity scenario.
Source: U.S. EPA Analysis, 2013

Table B-4: Projected 2014 Price (Cents per KWh of Sales) and Potential Price Increase Due to Compliance Costs for Options 3 and 4 by Sensitivity Scenario ($2010)[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
Option 3											
Proposed Option[d]	**0.015**	**10.95**	**0.13%**	**9.23**	**0.16%**	**6.03**	**0.24%**	**10.10**	**0.14%**	**9.03**	**0.16%**
Future-a[e]	0.016	10.95	0.14%	9.23	0.17%	6.03	0.26%	10.10	0.16%	9.03	0.17%
Future-b[e]	0.016	10.95	0.15%	9.23	0.17%	6.03	0.27%	10.10	0.16%	9.03	0.18%
All Units[d]	0.015	10.95	0.14%	9.23	0.16%	6.03	0.25%	10.10	0.15%	9.03	0.16%
Immediate[d]	0.017	10.95	0.16%	9.23	0.19%	6.03	0.29%	10.10	0.17%	9.03	0.19%
50-50 CPT[d]	0.007	10.95	0.07%	9.23	0.08%	6.03	0.12%	10.10	0.07%	9.03	0.08%

Table B-4: Projected 2014 Price (Cents per KWh of Sales) and Potential Price Increase Due to Compliance Costs for Options 3 and 4 by Sensitivity Scenario ($2010)[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
Option 4											
Proposed Option[d]	**0.036**	**10.95**	**0.33%**	**9.23**	**0.39%**	**6.03**	**0.59%**	**10.10**	**0.35%**	**9.03**	**0.40%**
Future-a[e]	0.037	10.95	0.34%	9.23	0.40%	6.03	0.61%	10.10	0.37%	9.03	0.41%
Future-b[e]	0.037	10.95	0.34%	9.23	0.40%	6.03	0.62%	10.10	0.37%	9.03	0.41%
All Units[d]	0.037	10.95	0.34%	9.23	0.40%	6.03	0.61%	10.10	0.36%	9.03	0.41%
Immediate[d]	0.042	10.95	0.39%	9.23	0.46%	6.03	0.70%	10.10	0.42%	9.03	0.47%
50-50 CPT[d]	0.018	10.95	0.16%	9.23	0.19%	6.03	0.30%	10.10	0.18%	9.03	0.20%

a. See *Chapter 4* for a detailed discussion of the methodology used to conduct this analysis.
b. Cost estimates are for 1,079 plants analyzed for the proposed Options 3 and 4.
c. Cost estimates are for 1,084 plants analyzed under this sensitivity scenario.
Source: U.S. EPA Analysis, 2013; U.S. DOE, 2010b; U.S. DOE, 2009c

Table B-5: Average Annual Cost per Household in 2014 for Options 3 and 4 by Sensitivity Scenario ($2010)[a]

Sensitivity Scenario	Total Annual Compliance Cost (at 2014; Million; $2010)	Total Electricity Sales (at 2014; MWh)	Compliance Cost per Unit of Sales ($2010/MWh)	Residential Electricity Sales (at 2014; MWh)	Number of Households (at 2014)	Residential Sales per Residential Consumer (MWh)	Annual Compliance Cost per Household ($2010)
Option 3							
Proposed Option[d]	**$561.4**	**3,831,895,945**	**$0.15**	**1,346,997,293**	**123,983,263**	**10.86**	**$1.59**
Future-a[e]	$602.7	3,831,895,945	$0.16	1,346,997,293	123,983,263	10.86	$1.71
Future-b[e]	$615.2	3,831,895,945	$0.16	1,346,997,293	123,983,263	10.86	$1.74
All Units[d]	$566.6	3,831,895,945	$0.15	1,346,997,293	123,983,263	10.86	$1.61
Immediate[d]	$662.1	3,831,895,945	$0.17	1,346,997,293	123,983,263	10.86	$1.88
50-50 CPT[d]	$561.4	3,831,895,945	$0.07	1,346,997,293	123,983,263	10.86	$0.80
Option 4							
Proposed Option[d]	**$1,373.2**	**3,831,895,945**	**$0.36**	**1,346,997,293**	**123,983,263**	**10.86**	**$3.89**
Future-a[e]	$1,414.6	3,831,895,945	0.037	1,346,997,293	123,983,263	10.86	$4.01
Future-b[e]	$1,427.1	3,831,895,945	0.037	1,346,997,293	123,983,263	10.86	$4.05
All Units[d]	$1,412.4	3,831,895,945	$0.37	1,346,997,293	123,983,263	10.86	$4.00
Immediate[d]	$1,620.1	3,831,895,945	$0.42	1,346,997,293	123,983,263	10.86	$4.59
50-50 CPT[d]	$1,373.2	3,831,895,945	$0.18	1,346,997,293	123,983,263	10.86	$1.95

a. See *Chapter 4* for a detailed discussion of the methodology used to conduct this analysis.
b. Cost estimates are for 1,079 plants analyzed for the proposed Options 3 and 4.
c. Cost estimates are for 1,084 plants analyzed under this sensitivity scenario.
U.S. EPA Analysis, 2013; U.S. DOE, 2010b; U.S. DOE, 2009c

Table B-6: Estimated Cost-To-Revenue Impact on Small Parent Entities for Options 3 and 4 by Sensitivity Scenario[a,b]

Sensitivity Scenario	Case 1: Lower bound estimate of number of entities owning steam electric plants				Case 2: Upper bound estimate of number of entities owning steam electric plants			
	Cost ≥ 1% of Revenue		Cost ≥ 3% of Revenue		Cost ≥ 1% of Revenue		Cost ≥3% of Revenue	
	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]
Option 3								
Proposed Option[d]	**5**	**5.2%**	**3**	**3.1%**	**5**	**2.9%**	**3**	**1.8%**
Future-a[e]	7	7.1%	4	4.1%	7	4.1%	4	2.3%
Future-b[e]	7	7.1%	4	4.1%	7	4.1%	4	2.3%
All Units[d]	5	5.2%	3	3.1%	5	2.9%	3	1.8%

Table B-6: Estimated Cost-To-Revenue Impact on Small Parent Entities for Options 3 and 4 by Sensitivity Scenario[a,b]

Sensitivity Scenario	Case 1: Lower bound estimate of number of entities owning steam electric plants				Case 2: Upper bound estimate of number of entities owning steam electric plants			
	Cost ≥ 1% of Revenue		Cost ≥ 3% of Revenue		Cost ≥ 1% of Revenue		Cost ≥3% of Revenue	
	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]
Immediate[d]	5	5.2%	3	3.1%	5	2.9%	3	1.8%
50-50 CPT[d]	5	5.2%	3	3.1%	5	2.9%	3	1.8%
Option 4								
Proposed Option[d]	**12**	**12.4%**	**4**	**4.1%**	**12**	**7.1%**	**4**	**2.4%**
Future-a[e]	13	13.3%	6	6.1%	13	7.6%	6	3.5%
Future-b[e]	13	13.3%	6	6.1%	13	7.6%	6	3.5%
All Units[d]	17	17.5%	7	7.2%	17	10.0%	7	4.1%
Immediate[d]	12	12.4%	4	4.1%	12	7.1%	4	2.4%
50-50 CPT[d]	12	12.4%	4	4.1%	12	7.1%	4	2.4%

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 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 97 (Case 1) and 170 (Case 2) small entities owning steam electric plants regardless of whether these plants are expected to incur compliance technology costs under any of the regulatory options.
d. Percentage values were calculated relative to the total of 98 (Case 1) and 171 (Case 2) small entities owning steam electric plants regardless of whether these plants are expected to incur compliance technology costs under any of the regulatory options.
e. This analysis was conduction for 97 small entities (Case 1) and 170 small entities (Case 2) owning 1,079 plants analyzed for the proposed Options 3 and 4.
f. This analysis was conduction for 98 small entities (Case 1) and 171 small entities (Case 2) owning 1,084 plants analyzed under this sensitivity scenario.
Source: U.S. EPA Analysis, 2013

Table B-7: Ongoing Employment Effects on the Electric Power Industry Sector Estimated for Options 3 and 4 by Sensitivity Scenario (Number of Jobs)[a,b]

Sensitivity Scenario	Total Annual Average Employment Effect (Number of Jobs)	95% Confidence Interval on Total Effect (Number of Jobs)	
		Lower Bound	Upper Bound
Option 3			
Proposed Option[c]	**519**	**-951**	**1,989**
Future-a[d]	556	-1,019	2,131
Future-b[d]	567	-1,039	2,173
All Units[c]	524	-960	2,007
Immediate[c]	557	-1,021	2,136
Option 4			
Proposed Option[c]	**1,253**	**-2,296**	**4,802**
Future-a[d]	1,290	-2,364	4,944
Future-b[d]	1,301	-2,384	4,986
All Units[c]	1,289	-2,362	4,941
Immediate[c]	1,345	-2,464	5,153

a. See *Chapter 6* for a detailed discussion of the methodology used to conduct this analysis.
b. Because employment effects are assessed on the basis of costs to society, the change in the cost-pass-through assumption is irrelevant for this analysis. Consequently, EPA did not conduct analysis of Sensitivity Scenario 4: Fifty-Percent Cost-Pass-Through.
c. This sensitivity analysis was conducted for 1,079 plants analyzed for the proposed Options 3 and 4.
d. This sensitivity analysis was conducted for 1,084 plants analyzed under this sensitivity scenario.
Source: U.S. EPA Analysis, 2013

Table B-8: Summary of Annualized Costs of Compliance to Society for Options 3 and 4 by Sensitivity Scenario (Millions; $2010)[a,b]

Sensitivity Scenario	At 3 Percent	At 7 Percent
Option 3		

Table B-8: Summary of Annualized Costs of Compliance to Society for Options 3 and 4 by Sensitivity Scenario (Millions; $2010)[a,b]

Sensitivity Scenario	At 3 Percent	At 7 Percent
Proposed Option[c]	**$572.0**	**$545.3**
Future-a[d]	$612.9	$585.1
Future-b[d]	$625.1	$597.4
All Units[c]	$577.2	$550.4
Immediate[c]	$614.4	$654.0
Option 4		
Proposed Option[c]	**$1,381.2**	**$1,323.2**
Future-a[d]	$1,422.0	$1,363.0
Future-b[d]	$1,434.2	$1,375.3
All Units[c]	$1,421.1	$1,360.7
Immediate[c]	$1,482.3	$1,585.8

a. See *Chapter 11* of the Benefits and Costs Analysis for the Proposed Effluent 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.

b. The change in the cost-pass-through assumption is irrelevant for this analysis. Consequently, EPA did not conduct analysis of Sensitivity Scenario 4: Fifty-Percent Cost-Pass-Through.

c. Cost estimates are for 1,079 plants analyzed for the proposed Options 3 and 4.

d. Cost estimates are for 1,084 plants analyzed under this sensitivity scenario.

Source: U.S. EPA Analysis, 2013

C Overview of IPM and Its Use for the Market Model Analysis of the Proposed ELGs

As discussed in *Chapter 5: Electricity Market Model Analysis*, to assess the impacts of the Steam Electric Power Generating Point Source Category (proposed 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 proposed ELG options, EPA used an updated version of this model: Integrated Planning Model Version 4.10 MATS (IPM V4.10) (U.S. EPA, 2010c). This analysis is meant to inform EPA‟s assessment of the economic achievability of the proposed ELGs under CWA Section 304(b)(2). This *Appendix* provides an overview of IPM V4.10, which is the basis of the Market Model Analysis for the proposed ELG regulatory options.

C.1 Overview of the Integrated Planning Model

IPM V4.10 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.

C.2 Key Specifications of the IPM V4.10

Power Plant Universe

IPM V4.10 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 (2006) and EIA 767 (2005).[112,113] The IPM V4.10 universe consists of 14,920 generating units accounting for 4,910 existing electric power plants. The modeling system includes nearly all steam electric generating plants subject to the proposed ELGs and which are estimated to incur compliance costs for the two options EPA analyzed using IPM. Plants excluded from the IPM analysis include 1 plant in Alaska (which is outside the geographic scope of the model), 5 plants excluded from the IPM baseline as the result of custom adjustments made by ICF, and 2 plants that were not surveyed.[114]

<u>*Potential (New) Units*</u>

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.[115]

<u>*Electricity Demand Baseline*</u>

IPM Version 4.10 embeds a baseline energy demand forecast that is derived from the Department of Energy‟s *Annual Energy Outlook 2010* (*AEO2010*), 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.

<u>*Regional Analysis Framework*</u>

IPM V4.10 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 C-1*provides a map of the NERC regions and *Table C-1* lists the regions included in IPM V4.10 and a crosswalk between these NERC regions and the IPM regions.

112 IPM generating unit universe foes not include generating units in Hawaii or Alaska.

113 In some instances, plant information has been updated to reflect known material changes in a plant‟s generating capacity since 2005.

114 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 5 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 analyzed in the IPM-based electricity market analyses.

115 For more information see IPM documentation available at http://www.epa.gov/airmarkets/progsregs/epa-ipm/index.html.

Figure C-1: 2012 North American Electric Reliability Corporation (NERC) Regions

a. The ASCC and HICC are not shown.
b. Texas Reliability Entity, Inc was established in 2006 to ensure the reliability of the bulk power system in the Electric Reliability Council of Texas (ERCOT) NERC region. Subsequently, this NERC region became known as TRE. For the purpose of our analysis, we refer to this region as ERCOT.
Source: U.S. DOE, 2012c

Table C-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[b]	Texas Regional Entity	ERCT
FRCC	Florida Reliability Coordinating Council	FRCC
HICC	Hawaii	Hawaii plants are not included in IPM
MRO	Midwest Reliability Organization	MRO, WUMS
NPCC	Northeast Power Coordination Council	DSNY, LILC, NENG, NYC, UPNY
RFC	ReliabilityFirst Council	COMD, MACE, MACS, MACW, MECS, RFCO, RFCP
SERC	Southeastern Electricity Reliability Council	ENTG, GWAY, SOU, TVA, TVAK, VACA, VAPW
SPP	Southwest Power Pool	SPPN, SPPS
WECC	Western Electricity Coordinating Council	AZNM, CA-N, CA-S, NWPE, PNW, RMPA, SNV

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.
b. Texas Reliability Entity, Inc was established in 2006 to ensure the reliability of the bulk power system in the Electric Reliability Council of Texas (ERCOT) NERC region. Subsequently, this NERC region became known as TRE. For the purpose of our analysis, we refer to this region as ERCOT.
Source: U.S. EPA, 2012c

Regulations Accounted for in the IPM Analysis Baseline

An important reason for using IPM for analyses of the proposed 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 proposed 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 V4.10 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.[116,117]

<u>*Treatment of Individual Plants and Generating Units*</u>

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.[118]

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 proposed ELG options.

<u>*Model Run Years*</u>

IPM V4.10 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 proposed 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 proposed ELGs and the years to which these run years map.

Table C-2: IPM V4.10 Run-Year Specification[a]

Run Year	Map Years
2015	2014-2016
2020	2017-2024
2030	2025-2034

a. IPM V4.10 also models run years 2012 (2012-2013), 2040 (2035-2045), and 2050 (2046-2054). However, EPA did not use the data for these run years to assess the impact of the proposed ELGs.

116 For more information on IPM V4.10 see http://www.epa.gov/airmarkets/progsregs/epa-ipm/index.html.

117 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 proposed ELG.

118 For more information on IPM V4.10 see http://www.epa.gov/airmarkets/progsregs/epa-ipm/index.html.

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 proposed 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.

D Cost Effectiveness

D.1 Introduction

EPA is proposing a regulation that would strengthen 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.

This appendix describes EPA‟s analysis of the cost-effectiveness of the proposed ELGs. It also compares the cost-effectiveness of the proposed ELGs with that of other promulgated ELGs.

D.2 Methodology

D.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. EPA often uses cost-effectiveness analysis in the development or revision of effluent limitations guidelines and standards to evaluate the relative efficiency of alternative regulatory options in removing toxic pollutants from the effluent discharges to the nation's waters. Although not required by the Clean Water Act, cost-effectiveness analysis is a useful tool for evaluating regulatory options that address toxic pollutants.

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:

1. Determine the pollutants considered for regulation–so-called “pollutants of concern.”
2. For each pollutant, obtain relative toxic weights and POTW removal factors (as discussed in Section D.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).
3. Define the regulatory pollution control options.
4. Calculate pollutant removals and toxic-weighted pollutant removals for each control option and for each of direct and indirect discharges.
5. Determine the total annualized compliance cost for each control option and for direct and indirect dischargers.
6. Adjust the cost obtained in step 5 to 1981 dollars.
7. Calculate the cost-effectiveness ratios for each control option and for direct and indirect dischargers.

D.2.2 Toxic Weights of Pollutants and POTW Removal

The *Technical Development Document (TDD)* provides information on the pollutants of concern addressed by the proposed ELGs (U.S. EPA, 2012c). The 46 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.[119] 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.[120] 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.

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 can derive the total toxic-weighted pollutant removals (pound 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 comply with the regulation 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 plant‟s cadmium that are ultimately discharged to surface waters at baseline, or 4 pounds.

For this analysis, EPA used the TWF and POTW removal efficiencies values most recently revised in 2006 and used in subsequent Effluent Guidelines Program Plans (U.S. EPA, 2006; 2011c). *Table D-1* lists the

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119 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.

120 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).

pollutants that are considered in the cost-effectiveness analysis and presents their TWFs and POTW removal efficiencies, if applicable.[121]

Table D-1: Pollutants of Concern for Proposed ELGs, Toxic Weighting Factors, and POTW Removal Percentage

Pollutant Name	Toxic Weighting Factor	POTW Removal (%)
Aluminum	0.06469	91%
Ammonia	0.00135	39%
Antimony	0.01225	67%
Arsenic	4.04133	66%
Barium	0.00199	55%
Beryllium	1.05660	61%
Biochemical Oxygen Demand	N/A	N/A
Boron	0.00834	2%
Cadmium	23.11680	90%
Calcium	0.00003	N/A
Chloride	0.00002	N/A
Chromium	0.07570	80%
Cobalt	0.11429	10%
Copper	0.63482	84%
Cyanide, Total	1.11692	70%
Fluoride	0.03500	
Hexane Extractable Material	N/A	80%
Chromium (VI)	0.51656	N/A
Iron	0.00560	N/A
Lead	2.24000	77%
Magnesium	0.00087	N/A
Manganese	0.07043	41%
Mercury	117.11802	90%
Molybdenum	0.20144	N/A
Nickel	0.10891	51%
Nitrate Nitrite as N	0.00320	90%
Nitrogen, Total Organic (as N)	N/A	N/A
Oil and Grease	N/A	N/A
Phosphorus, Total	N/A	N/A
Selenium	1.12134	34%
Silver	16.47073	88%
Sodium	0.00001	N/A
Sulfate	0.00001	N/A
Sulfide (as S)	2.80145	
Sulfite (as SO3)	N/A	
Thallium	1.02706	54%
Tin	0.30108	N/A
Titanium	0.02932	N/A
Total Dissolved Solids	N/A	N/A
Nitrogen, Kjeldahl	N/A	N/A
Total Suspended Solids	N/A	N/A
Vanadium	0.03500	8%
Yttrium	N/A	
Zinc	0.04689	79%

N/A: Not applicable. The pollutant has a toxic weighting factor of zero and is therefore not included in the cost-effectiveness analysis.

Source: U.S. EPA, 2012c

121 See the Technical Development Document for a description of POTW removal efficiencies.

D.2.3 Regulatory Options

EPA analyzed the eight regulatory options evaluated for the proposed ELGs (see *Table 1-2*). The *TDD* provides additional information on the control technologies and regulatory options (U.S. EPA, 2012c).

D.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, 2012c; DCN SE01964).

Pollutant removals are calculated simply as the difference between the baseline and post-compliance loadings under each regulatory option [122] 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:

$$\text{[Eq. 2]} \qquad Total\ direct\ removals = \sum_{i=1}^{46} Direct\ Removals\ (lbs)_i \times TWF_i$$

For indirect dischargers, pound equivalent removals are calculated as:

$$\text{[Eq. 3]} \qquad Total\ indirect\ removals = \sum_{i=1}^{46} Indirect\ Removals\ (lbs)_i \times TWF_i \times POTW\%_i$$

Table D-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 D-2: Pollutant Removal by Regulatory Option

Option	Toxic-Weighted Removals (lbs-eq/yr)		
	Direct Discharge	Indirect Discharge	Total[a]
1	1,530,719	3,540	1,534,259
3a	2,488,470	0	2,488,470
2	2,603,628	11,711	2,615,339
3b	3,396,653	0	3,396,653
3	5,092,098	11,711	5,103,809
4a	6,664,693	11,711	6,676,404
4	7,831,298	15,532	7,846,830
5	8,200,804	18,297	8,219,101

[a] Total may not add up due to independent rounding.

Source: U.S. EPA, 2012c

D.2.5 Annualized Compliance Costs

EPA developed costs for technology controls to address each of the wastestreams present at each steam electric plant. The *TDD* provides additional details on the methods used to estimate the costs of complying with the regulatory options (U.S. EPA, 2012c). 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 plant may be subject to requirements for one or more wastestreams, depending on the plant configuration, technologies in use, or other site-specific factors. The

122 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.

cost estimates reflect the incremental costs attributed only to the proposed ELGs, accounting for wastestreams and treatment systems present in the baseline.[123]

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.[124] Finally, EPA applied sample weights to the costs for surveyed plants to obtain total costs for the 1,079 steam electric plants. *Table D-3* summarizes the total annualized compliance costs used in calculating cost-effectiveness of the eight options.

Table D-3: Total Annualized Compliance Costs by Regulatory Option

Option	Total Annualized Compliance Costs (Million 2010$)		
	Direct Discharge	Indirect Discharge	Total[a]
1	$262.9	$3.0	$265.9
3a	$168.1	$0.0	$168.1
2	$388.4	$4.9	$393.3
3b	$264.6	$0.0	$264.6
3	$556.4	$4.9	$561.3
4a	$942.9	$4.9	$947.8
4	$1,364.3	$9.0	$1,373.2
5	$2,257.0	$20.3	$2,277.3

[a] Total may not add up due to independent rounding.
Source: U.S. EPA analysis, 2013

D.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 proposed ELGs to those of other promulgated rules, EPA adjusts compliance costs for this analysis from 2010 to 1981 dollars using *Engineering News Record's* Construction Cost Index (CCI) as follows:

[Eq. 4] $$\text{Adjustment factor} = \frac{CCI_{1981}}{CCI_{2010}} = \frac{3535}{8802} = 0.402$$

The equation used to calculate incremental cost-effectiveness is:

123 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 proposed treatment level, EPA conservatively assumed that the plant would incur the full compliance costs for the treatment control under the proposed rule (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.

124 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.

[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.

D.2.7 Comparisons of Cost-Effectiveness Values

EPA presents two comparisons of the cost-effectiveness values for the proposed 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.

D.3 Cost-Effectiveness Analysis Results

EPA prepared the cost-effectiveness analyses for the eight regulatory options summarized in *Table D-1*. 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 proposed ELGs (*Section D.3.1*). It then compares the cost-effectiveness values to those for ELGs previously promulgated for other industrial categories (*Section D.3.2*).

D.3.1 Cost-Effectiveness of Regulatory Options

Table D-4 shows the cost-effectiveness results for the eight regulatory options EPA considered in the proposed ELGs for direct and indirect dischargers.

Cost effectiveness values for direct dischargers range from \$44/lb-eq to \$111/lb-eq, with options 3a and 5 being the most and least cost-effective, respectively. For indirect dischargers, cost effectiveness values range from \$168/lb-eq to \$445/lb-eq, with Options 2, 3, and 4a being the most cost-effective, and Option 5 being the least cost-effective. Incremental toxic-weighted pollutant removals achieved by moving from Option 2 to Option 3b come at the lowest incremental cost (-\$63/lb-eq) for direct dischargers.

Table D-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
Direct	1	$105.6	$105.6	1,530,719	1,530,719	$69	$69
	3a	$67.5	-$38.1	2,488,470	957,751	$27	-$40
	2	$156.0	$88.5	2,603,628	115,158	$60	$768
	3b	$106.3	-$49.7	3,396,653	793,025	$31	-$63

Table D-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
	3	$223.5	$67.5	5,092,098	2,488,469	$44	$27
	4a	$378.7	$155.2	6,664,693	1,572,595	$57	$99
	4	$547.9	$169.2	7,831,298	1,166,605	$70	$145
	5	$906.5	$358.5	8,200,804	369,506	$111	$970
Indirect	3a	$0.0	$0.0	0	0	--	--
	3b	$0.0	$0.0	0	0	--	--
	1	$1.2	$1.2	3,540	3,540	$345	$345
	2	$2.0	$0.7	11,711	8,172	$168	$92
	3	$2.0	$0.0	11,711	0	$168	--
	4a	$2.0	$0.0	11,711	0	$168	--
	4	$3.6	$1.6	15,532	3,821	$233	$430
	5	$8.1	$4.5	18,297	2,765	$445	$1,636

[a] Incremental costs (and removals) are compared to those for the next least stringent option – for direct dischargers under Option 1, the incremental costs (and removals) are calculated relative to baseline (i.e., 0), for Option 3a, the incremental costs (and removals) are calculated relative to those of Option 1, etc.

Source: U.S. EPA analysis, 2013

D.3.2 Comparison with Previously Promulgated Effluent Guidelines and Standards

Table D-5 presents, for direct dischargers across a range of industries, the estimated cost-effectiveness for promulgated ELGs. *Table D-6* provides similar information for indirect dischargers.

The values presented in the table can be compared to the cost-effectiveness calculated for the proposed 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 four preferred BAT technology bases for direct dischargers ranges from $27 to $57 (see *Table D-4*). This is comparable to cost effectiveness ratios for BAT of other industries shown in *Table D-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 two preferred PSES options that reduce loads from indirect dischargers (Options 3 and 4a; see *Table D-4*) have a cost effectiveness of $168/lb-eq ($1981). These cost effectiveness ratios are comparable to cost-effectiveness for PSES of other industries shown in *Table D-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 D-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

Table D-5: Industry Comparison of Cost-Effectiveness for Direct Dischargers

Industry	40 CFR Part	Year	Cost-Effectiveness ($1981/lb.eq.)[a]
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, Formulating and Packaging	455	1993	15
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.

Table D-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

Table D-6: Industry Comparison Cost-Effectiveness for Indirect Dischargers

Industry	40 CFR Part	Year	Cost-Effectiveness ($1981/lb.eq.)[a]
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	1993	<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.

As noted in *Section D.2.2*, EPA has revised the TWFs for some priority pollutants since all of the ELGs were promulgated. The comparison provided above, therefore, is somewhat inexact since the cost-effectiveness of the previously promulgated ELGs was calculated using different TWFs than the cost-effectiveness of the proposed ELGs for the steam electric industry. Overall, changes made to the TWFs in 2006 tend to result in lower toxic-weighted pollutant removals for the proposed ELGs than would have been estimated using older TWFs. For example, using TWF values from 2004 provides total toxic-weighted removals for Option 3 of 9.6 million lb-eq, instead of 5.1 million lb-eq calculated using the current TWFs. Accordingly, using pre-2006 TWF values would result in cost-effectiveness values for Option 3 that are about half of those discussed in *Section D.3.1*, and improves the cost-effectiveness of the steam electric proposed ELGs relative to that of ELGs EPA promulgated for other industrial categories.