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Analysis of the Impacts of the Clean Power Plan

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Background, Methodology, and Scenarios

This report responds to an August 2014 request to the U.S. Energy Information Administration (EIA) from Representative Lamar Smith, Chairman of the U.S. House of Representatives Committee on Science, Space, and Technology, for an analysis of the Environmental Protection Agency's (EPA) proposed Clean Power Plan under which states would be required to develop plans to reduce carbon dioxide (CO_2) emissions rates from existing fossil-fired electricity generating units.[1] Appendix A provides a copy of the request letter.

The starting point for EIA's analysis of the Clean Power Plan is the *Annual Energy Outlook 2015* (AEO2015) Reference case rather than earlier AEO projections that were developed using versions of EIA's National Energy Modeling System (NEMS) that lack the model structure needed to analyze key features of the Clean Power Plan proposal. With EIA's decision, unrelated to this project, to publish shorter and longer editions of the AEO in alternating years, AEO2015 does not include all of the alternative cases presented in earlier AEO editions. However, in the spirit of Chairman Smith's request, this report analyzes the Clean Power Plan in the context of the AEO2015 High Economic Growth and High Oil and Gas Resource cases as well as the Reference case in order to examine indicators of the proposed rule's impacts on energy markets under varying assumptions regarding economic growth, electricity demand, and fuel prices.

To address some of the additional questions raised in Chairman Smith's request, the report includes additional Clean Power Plan sensitivity cases including: 1) extension of the Clean Power Plan targets beyond 2030 to reduce CO_2 emissions from electric power generation by 45% relative to the 2005 level by 2040; 2) treatment of future nuclear capacity similar to the treatment of renewable capacity; 3) sensitivities for expenditures and effectiveness of energy efficiency programs; 4) sensitivities for the cost and effectiveness of heat rate improvement measures; 5) no availability of markets for CO_2 captured from electric power plants for enhanced oil recovery (EOR); 6) an alternative compliance phase-in trajectory during the 2020-29 period; 7) alternative accounting rules for emissions from biomass generation; 8) national compliance cooperation; and 9) limited interregional trade.

Description of the proposed Clean Power Plan

Rulemaking history and status

In June 2014, EPA issued its proposed Clean Power Plan to regulate CO_2 emissions from existing power plants under section 111(d) of the Clean Air Act.[2] The Clean Power Plan proposes to limit carbon emissions from existing fossil fuel-fired electric generating units, including steam generating, integrated gasification combined cycle, or stationary combustion turbines (in either simple cycle or combined cycle

[1] U.S. Environmental Protection Agency, *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units* (Proposed Rule), 79 Fed. Reg. 34,830 (June 18, 2014), accessed January 10, 2015.
[2] Clean Air Act, 42 U.S.C. §§7401 et seq. (2013), §7411(d).

configuration) operating or under construction by January 8, 2014.[3]

In addition to the text of the proposed rule, EPA issued a Regulatory Impact Analysis for the Clean Power Plan,[4] along with numerous technical supporting documents and fact sheets.[5] In October 2014, EPA issued a notice of data availability, which provided discussion and solicited additional comment on several topic areas, including the 2020-29 compliance trajectories.[6] Also in October 2014, EPA issued a supplemental proposal to address carbon pollution from affected power plants in Indian Country and U.S. territories.[7] In November 2014, EPA issued an additional technical support document providing examples of how a state could translate its rate-based goal into an equivalent mass-based goal, expressed in metric tons of CO_2.[8] In November 2014, EPA also issued a memo addressing biogenic CO_2 emissions from stationary sources that explicitly relates this topic to the implementation of the Clean Power Plan.[9]

EPA's proposed Best System of Emissions Reduction and state-level CO_2 emission performance goals

In the proposed Clean Power Plan, EPA calculates the emissions reduction targets for individual states through application of a Best System of Emissions Reduction (BSER). The BSER consists of four building blocks which represent approaches to reducing CO_2 emissions rates from existing fossil fuel-fired generators as calculated for purposes of compliance:

Building block 1: Improving the thermal efficiency of individual affected sources (heat rate improvement)[10]

Building Block 2: Dispatching the generating fleet to substitute less-carbon-intensive affected sources for more-carbon-intensive affected sources (re-dispatch for reduced emissions)

Building Block 3: Expanding the use of low- or zero-carbon generation in order to displace affected sources (low- and zero-carbon capacity expansion)

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[3] U.S. Environmental Protection Agency, *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units* (Proposed Rule), 79 Fed. Reg. 34,830 (June 18, 2014), at 34,954, accessed January 10, 2015.

[4] U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, *Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emissions Standards for Modified and Reconstructed Power Plants*, EPA-452/R-14-002 (June, 2014), accessed December 30, 2014.

[5] U.S. Environmental Protection Agency, Clean Power Plan Proposed Rule Technical Documents, accessed January 10, 2015.

[6] U.S. Environmental Protection Agency, *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units* (Notice of Data Availability), 79 Fed. Reg. 69,543 (October 30, 2014), accessed January 31, 2015.

[7] U.S. Environmental Protection Agency, Carbon Pollution Emission Guidelines for Existing Stationary Sources: EGU's in Indian Country and U.S. Territories; Multi-Jurisdictional Partnerships (Supplemental Proposed Rulemaking), 79 Fed. Reg. 65,482 (November 4, 2014), accessed January 31, 2015.

[8] U.S. Environmental Protection Agency, Office of Air and Radiation, *Translation of the Clean Power Plan Emission Rate-Based CO_2 Goals to Mass-Based Equivalents*, Technical Support Document, Docket ID No. EPA-HQ-OAR-2013-0602 (November 2014), accessed January 10, 2015 [hereinafter "Mass-Based Equivalent Technical Support Document"].

[9] U.S. Environmental Protection Agency, Office of Air and Radiation, *Framework for Assessing Biogenic CO_2 Emissions from Stationary Sources* (November 2014)

[10] Heat rate is defined as a measure of generating station thermal efficiency, commonly stated in British thermal units (Btu) per kilowatthour (kWh). U.S. Energy Information Administration Glossary, accessed November 12, 2014.

Building Block 4: Employing the use of demand-side energy efficiency to reduce overall generation required from affected sources (demand-side energy efficiency)[11]

In determining state goals, EPA begins by calculating an affected fossil generation emissions rate, in pounds of CO_2 emissions per megawatt hour of electricity generated, based on 2012 historical data for each state. EPA then applies the building blocks of the BSER to arrive at each state's interim and final emission rate performance goals. The Clean Power Plan proposes that states begin to reduce CO_2 emissions from affected electric generating units by 2020 in order to reach final CO_2 emission performance goals, measured in pounds of CO_2 emitted per megawatthour of electricity generated from affected electric generating units, by 2030. The Clean Power Plan also proposes that states meet interim CO_2 emission performance goals, on average, over the 10-year compliance period from 2020-29.[12] The state-level emissions rates as calculated by EPA for 2012, as well as the interim targets for 2020-29 and the final targets for 2030 and beyond, specified in the proposed Clean Power Plan are provided in Appendix C, Table 25.

It is critical to recognize that while the BSER building blocks are used to establish state-level goals, each state has discretion in designing implementation plans to achieve outcomes that meet the goals. Two or more states may also cooperate to meet their combined goals jointly.

The state-level emissions performance goals under the proposed Clean Power Plan are not based on a simple emission rate calculation (emissions divided by generation) for generation provided by existing fossil-fired electric generating units. Rather, the goals are established and compliance is assessed using a formula that provides varying treatment of specific generation sources and demand-side efficiency programs that can displace CO_2 emissions from existing generating units that are regulated under the Clean Power Plan proposal. For example, unlimited amounts of new and existing zero-emission non-hydropower renewable generation are included in the generation base used to calculate compliance, which makes the non-hydropower renewable generation more valuable for compliance than existing hydropower and new and existing nuclear generation that do not receive similar treatment. The proposed Clean Power Plan formula also considers efficiency programs that reduce load as equivalent to zero-emission generation that counts in the base for the compliance calculation, even though some of the generation that is avoided by reduced load may have already been served by zero-emission generation sources.

[11] U.S. Environmental Protection Agency, *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units* (Proposed Rule), 79 Fed. Reg. 34,830 (June 18, 2014), at 34,851, accessed January 10, 2015.
[12] U.S. Environmental Protection Agency, *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units* (Proposed Rule), 79 Fed. Reg. 34,830 (June 18, 2014) at 34,838, accessed January 10, 2015. EPA also sought comment on an alternative regulatory option, consisting of a 5-year compliance period and a less-stringent set of CO_2 emission performance levels. The alternative option would require that states meet final emission performance levels by 2025, with interim goals met over the period from 2020-2024. In this report, EIA does not analyze the alternative 5-year option.

Methodology

The National Energy Modeling System

This report considers the proposed Clean Power Plan as modeled using EIA's National Energy Modeling System (NEMS). NEMS is a modular economic modeling system used by EIA to develop long-term projections of the U.S. energy sector, currently through the year 2040.[13]

The level of regional disaggregation in NEMS varies across sectors. For example, Lower 48 states electricity markets are represented using 22 regions, coal production is represented by 14 regions, and oil and natural gas production is represented in 9 regions. In many but not all cases, regional boundaries follow state borders. To the extent possible, this analysis represents the Clean Power Plan using regional targets derived from the state-level targets in the EPA proposal.

The Reference case projections developed in NEMS and published in the *Annual Energy Outlook 2015* generally reflect federal laws and regulations and state renewable portfolio standards (RPS) in effect at the time of the projection. The Reference case does not assume the extension of laws with sunset provisions. In keeping with the requirement that EIA remain policy-neutral, the Reference case does not include proposed regulations such as the Clean Power Plan.

For this report, EIA constructed cases in NEMS that represent compliance with the proposed Clean Power Plan, including:

- EPA's proposed carbon intensity targets during the interim and final compliance periods, enforced at the NEMS Electricity Market Module (EMM) region level
- Choice of heat rate improvements (HRI) based on the representation of the cost and degree of potential HRI incorporated in the current (AEO2015) version of NEMS[14]
- Re-dispatch of affected electric generating units as an available compliance strategy
- Credit in compliance calculations for generation from existing and new renewable capacity[15]
- Credit in compliance calculations for currently under-construction nuclear capacity and 6% of generation from existing nuclear capacity
- Expansion of new low- and zero-carbon-emitting generating capacity, including representation of state renewable portfolio standards (RPS)[16]

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[13] For additional information, see U.S. Energy Information Administration, *The National Energy Modeling System: An Overview 2009*, DOE/EIA-0581(2009) (October 2009), accessed January 10, 2015.

[14] U.S. Energy Information Administration, *Analysis of Heat Rate Improvement Potential at Coal-Fired Power Plants*, (May 2015).

[15] Excludes existing hydroelectric generation, and excludes existing and new municipal solid waste generation. The model compliance calculation does credit incremental hydroelectric generation added by NEMS. See *Clean Power Plan* at ¶630, "The exclusion of pre-existing hydropower generation from the baseline of this target-setting framework does not prevent states from considering incremental hydropower generation from existing facilities (or later-built facilities) as an option for compliance with state goals."

[16] U.S. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2015* (2015). NEMS modeling only represents those RPS targets having established enforcement provisions or state funding mechanisms.

- Credit in compliance calculations for avoided generation as a result of incremental demand-side energy efficiency savings achieved through energy efficiency measures in the residential and commercial sectors [17]
- A phased-in 2020-29 compliance trajectory, to reflect that the proposed rule allows states flexibility to determine their pre-2030 trajectory, if they meet interim targets on a 10-year average or cumulative basis

By explicitly modeling the intensity targets, NEMS does not require or assume specific levels for individual compliance strategies. The discussion of EIA's analysis presents results in terms of the compliance options used to meet the regionalized Clean Power Plan targets.

Regional groupings

As noted above, NEMS is not a state-level model. The Electricity Market Module (EMM) builds and dispatches electric generating capacity in twenty-two distinct geographic regions, as shown in Figure 1 and described in Table 1.[18]

For modeling purposes, EIA treats EMM regions as Clean Power Plan compliance regions in the bulk of this analysis. The model assigns each EMM region an emission performance goal in each compliance year from 2020-29, and holds the final goal constant from 2030 onwards. The modeled EMM regional goals, provided in Appendix D, Table 25, are consistent with EPA's proposed state-level goals.[19]

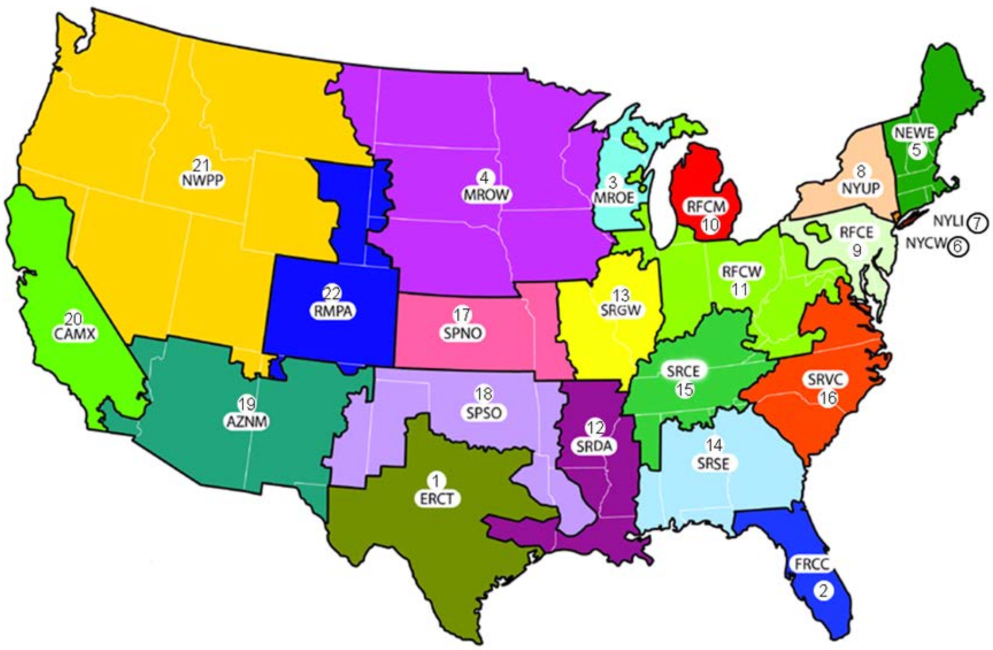
End-use sector models within NEMS, including the Residential Demand Module and the Commercial Demand Module, are Census region-based rather than state-level models. For this analysis, the end-use sector models determine results of incremental demand-side energy efficiency activities by U.S. Census division (Figure 2) and then map the savings to Electricity Market Module regions.

[17] U.S. Energy Information Administration, *Analysis of Energy Efficiency Program Impacts Based on Program Spending*, (May 2015).

[18] The Electricity Market Module regions shown in Figure 1 were developed and implemented in NEMS for the *Annual Energy Outlook 2011*, and corresponded to the North American Reliability Corporation (NERC) regions in place at that time, divided into sub-regions. See U.S. Energy Information Administration, *Annual Energy Outlook 2011, Electricity Market Module Documentation* at p. 16, accessed January 2, 2015.

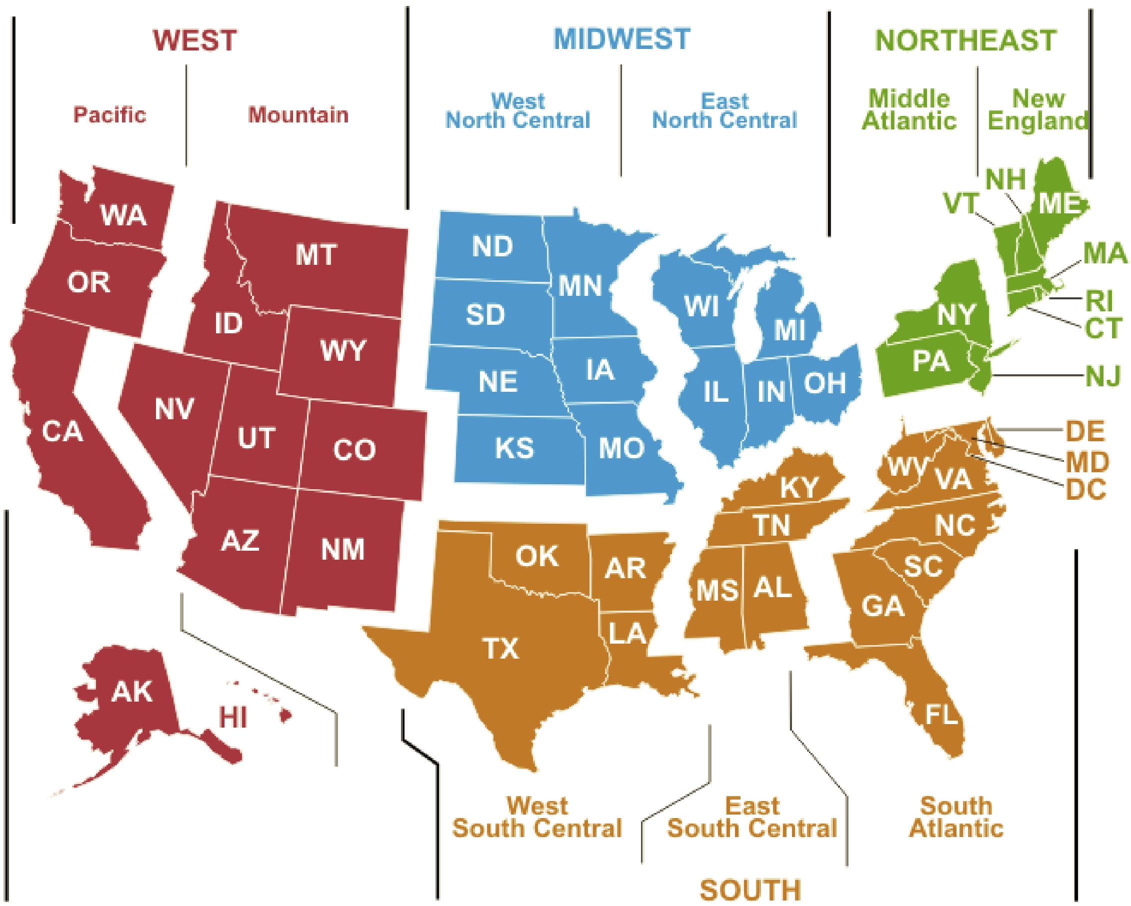
[19] The 2012 historical generation-weighted average goal for each state in an EMM region is used as the basis for translating from EPA's state goals to EMM regional goals.

Figure 1. NEMS Electricity Market Module regions



Source: U.S. Energy Information Administration.

Figure 2. United States Census Divisions



Source: U.S. Energy Information Administration.

Table 1. NEMS EMM Regions

Number	Abbreviation	NERC Sub Region Name	Geographic Name*
1	ERCT	Texas Regional Entity	Texas
2	FRCC	Florida Reliability Coordinating Council	Florida
3	MROE	Midwest Reliability Council – East	Eastern Wisconsin
4	MROW	Midwest Reliability Council – West	Northern Plains
5	NEWE	Northeast Power Coordinating Council/ Northeast	New England
6	NYCW	Northeast Power Coordinating Council/ New York City-Westchester	New York City
7	NYLI	Northeast Power Coordinating Council/ Long Island	Long Island
8	NYUP	Northeast Power Coordinating Council/ Upstate New York	Upstate New York
9	RFCE	ReliabilityFirst Corporation – East	Mid-Atlantic
10	RFCM	ReliabilityFirst Corporation – Michigan	Lower Michigan
11	RFCW	ReliabilityFirst Corporation – West	Great Lakes
12	SRDA	SERC Reliability Corporation (SERC)-Delta	Mississippi Delta
13	SRGW	SERC – Gateway	Mississippi Basin
14	SRSE	SERC – Southeast	Southeast
15	SRCE	SERC – Central	Tennessee Valley
16	SRVC	SERC – Virginia-Carolina	Virginia-Carolina
17	SPNO	Southwest Power Pool North	Central Plains
18	SPSO	Southwest Power Pool South	Southern Plains
19	AZNM	Western Electricity Coordinating Council (WECC) – Arizona New Mexico	Southwest
20	CAMX	WECC – California	California
21	NWPP	WECC – Northwest Power Pool Area	Northwest
22	RMPA	WECC – Rocky Mountain	Rocky Mountain

* Names are intended to be approximately descriptive of location. Exact regional boundaries do not necessarily correspond to state borders or to other regional naming conventions.
Note: EIA groups Regions 6, 7, and 8 (New York City, Long Island, and Upstate New York) into a single Clean Power Plan compliance region in the Base Policy case and in the alternative cases.
Source: U.S. Energy Information Administration.

Caveats regarding interpretation of this analysis

Consistent with EIA's statutory mission and expertise, this analysis focuses on the implications for the energy system and the economy of reducing CO_2 emissions under the proposed Clean Power Plan. It does not consider any potential health or environmental benefits from reducing CO_2 emissions from existing electric generating units covered by the proposed Clean Power Plan. It is not a cost-benefit analysis.

Additionally, this analysis represents other laws and regulations as modeled in NEMS. The Reference case used as the starting point for this analysis is the *Annual Energy Outlook 2015* (AEO2015) Reference case, which generally reflects laws and regulations in effect as of October 2014.

EIA recognizes that projections over a 25-year horizon are inherently uncertain and subject to changing policy objectives, supply disruptions, the emergence of disruptive technologies, and other future developments. It is not possible for EIA to account for all uncertainties; for practical reasons this study examines a limited set of sensitivities through alternative scenario analysis.

Additionally, there is considerable uncertainty and many challenges are involved in projecting the impacts of the proposed Clean Power Plan.

- The Clean Power Plan is still a proposed rule as of the date of this report; the final rule may differ from the proposed rule in material ways.
- The regional compliance patterns presented in this analysis are model outputs from NEMS, while actual compliance mechanisms will be defined by state compliance proposals and may have different characteristics.
- The construction of new generation to comply with the Clean Power Plan may necessitate upgrades to, and expansion of, electric power transmission systems; however, NEMS does not include transfer limits on intraregional power trade, nor does it contain a power-flow model or assess the reliability of bulk power transmission systems in detail.
- NEMS does not consider how deliverability of natural gas to power plants using that fuel might be impacted by extreme cold conditions in regions where natural gas is a primary fuel for residential and commercial heating and local natural gas distribution companies typically have the first call on available firm natural gas transmission capacity.
- The modeled 2020-29 emission performance trajectory was developed outside of NEMS, as an approach to represent the proposed rule's flexibility within the existing NEMS framework.[20]
- Combustion turbines are not included in compliance calculations based on the assumption that only a small percentage would reach the output criteria proposed by EPA.
- NEMS does not model useful thermal output from power-sector combined heat and power (CHP) plants; therefore, this analysis applies a calculated average generation factor to power-sector CHP plants in NEMS in order to represent the Clean Power Plan's provision to account for useful thermal output from CHP.[21]

[20] The modeled trajectory attempts to impose lower carbon reductions in the early compliance years, within the constraints of maintaining the 10-year average interim emission performance goals, and not require any state to reduce its annual emission performance goal below its final 2030 target in any compliance year. This analysis also includes a sensitivity case showing the impact if the trajectory is assumed to be identical to the path shown in Appendix 1 to EPA's Goal Computation TSD.

[21] For the purposes of this analysis, end-use CHP is excluded from compliance calculations.

Treatment of New Nuclear Generating Capacity under EPA's Proposed Clean Power Plan rule for Existing Electric Generating Units under Clean Air Act Section 111(d)

The proposed Clean Power Plan Rule under section 111(d) is complex and subject to varying interpretation even before consideration of decisions that will be made by states to implement the rule that is finally promulgated. The treatment of new nuclear generation not already under construction illustrates the challenges in this area.

In developing its Base Policy case (CPP), EIA assumed that new nuclear generation beyond units already under construction would not receive the same treatment accorded under the rule to eligible renewable generation, which is counted in the denominator when calculating the average carbon dioxide intensity rate for generation from existing fossil-fuel units for compliance purposes. However, EIA also considered an alternative case (CPPNUC) that accorded all new nuclear power the same treatment as new eligible renewables in the compliance calculation.

EIA's assumption regarding the treatment of new nuclear units beyond those already under construction in the Base Policy case (CPP) is consistent with its reading of:

1) Language regarding the definition of "new nuclear generating capacity" from the proposed rule,[22] and

2) The rate-setting criteria[23] in the technical support documentation accompanying the proposed rule.

The proposed rule identifies new nuclear capacity as a potential source of carbon-free generation that can replace existing fossil-fueled power plants targeted under the program. EPA focuses on what it regards as the two most promising sources of additional nuclear output: 1) plants currently under construction, and 2) preservation of existing plants that might otherwise be retired, 5.7 GW of capacity, or roughly 6% of the share of nuclear capacity termed "at risk of retirement." Generation from "new" nuclear plants not already under construction is not presented as affected generation (i.e., the denominator of the average CO_2 intensity rate formula). States could allow generation from new, not-under-construction plants to displace generation (and emissions) from existing coal or natural gas plants that were accounted for in the emission rate computation. While this displacement would, presumably, help states meet their emission rate goal, the generation from these "new" plants would not be directly reflected in the base generation used to compute the goal.

EPA's "Goal Computation Technical Support Document" (TSD) accompanying the Federal Register Notice allows generation from "under construction" and "at risk [of retirement]" nuclear plants to count against the affected generation (in the denominator, as indicated in the equation below) used to compute the emission rate goals for each state.[24]

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[22] U.S. Environmental Protection Agency, *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Proposed Rule* Federal Register /Vol. 79, No. 117 /Wednesday, June 18, 2014 / page. 34871, https://www.federalregister.gov/articles/2014/06/18/2014-13726/carbon-pollution-emission-guidelines-for-existing-stationary-sources-electric-utility-generating#h-90.

[23] U.S. Environmental Protection Agency, *Goal Computation Technical Support Document*; June 2014 page 3, http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-goal-computation.pdf

[24] See page 18, Step 5: BSER Block Four in the *Goal Computation TSD*

$$\text{Emissions Rate} = \frac{(\text{coal gen} * \text{coal emission rate}) + (\text{OG gen} * \text{oil/gas emission rate}) + (\text{NGCC gen} * \text{NGCC emission rate}) + \text{other emissions}}{(\text{coal gen}) + (\text{oil/gas gen}) + (\text{NGCC gen}) + (\text{nuclear gen}_{\text{under construction + at risk}}) + (\text{RE gen}) + \text{EE gen}}$$

While these sections are relatively clear in describing how generation from nuclear plants is accounted for in the emission rate goals, other parts of the EPA proposal suggest the possibility that "new" nuclear plants beyond those currently under construction may play a role in state compliance planning. For example, in the proposal, EPA explicitly asks for comment on "whether we [EPA] should include in the state goals an estimated amount of additional nuclear capacity whose construction is sufficiently likely to merit evaluation for potential inclusion in the goal-setting computation."[25]

EIA's CPPNUC case reflects the possibility that generation from new nuclear capacity beyond units already under construction could be counted in the denominator of the compliance formula for existing fossil generation units. This case, which is featured prominently among the alternative scenarios in EIA's analysis, reflects only one of many uncertainties in the ultimate specification of the rule that EIA evaluated.

[25] See Section 2 "Cost of CO2 Emission Reductions from Nuclear Generation" Federal Register /Vol. 79, No. 117 /Wednesday, June 18, 2014 / Proposed Rules 34871, https://www.federalregister.gov/articles/2014/06/18/2014-13726/carbon-pollution-emission-guidelines-for-existing-stationary-sources-electric-utility-generating#h-90.

Scenario descriptions

Table 2 describes the EIA baseline cases and the main Clean Power Plan cases analyzed in this report.[26]

Table 2. Description of EIA baseline cases and Clean Power Plan cases

Case name	Description
Reference (AEO)	EIA's AEO2015 Reference case. AEO2015 presents annual projections of energy supply, demand, and prices through 2040. The Reference case is generally based on federal, state, and local laws and regulations as of October 2014.
Base Policy (CPP)	The Base Policy case models the proposed Clean Power Plan using the AEO2015 Reference case as the underlying baseline.
Policy Extension (CPPEXT)	The Policy Extension case extends CO_2 reduction targets beyond 2030, in order to reduce CO_2 emissions from the power sector by 45% below 2005 levels in 2040, using the AEO2015 Reference case as the baseline.
Policy with New Nuclear (CPPNUC)	The Policy with New Nuclear case models the Clean Power Plan assuming that generation from currently unplanned new nuclear capacity counts in compliance calculations. The baseline for the CPPNUC case is the AEO2015 Reference case.
Policy with Biomass CO_2 (CPPBIO195)	The Policy with Biomass CO_2 case models the Clean Power Plan assuming that the emission rate for biomass fuel is 195 pounds CO_2 per MMBtu, as assumed by EPA in its Regulatory Impact Analysis, in place of EIA's Reference case assumption that biomass is carbon neutral. The baseline for the CPPBIO195 case is the AEO2015 Reference case.
Cases using alternative baselines	
High Economic Growth (AEOHEG)	EIA's AEO2015 High Economic Growth case, which reflects higher growth in U.S. gross domestic product (GDP) than the Reference case, resulting in higher electricity demand and fuel prices.
High Oil and Gas Resource (AEOHOGR)	EIA's AEO2015 High Oil and Gas Resource case, which reflects more-optimistic assumptions about domestic oil and natural gas supply prospects than the Reference case, resulting in lower natural gas prices.
Policy with High Economic Growth (CPPHEG)	The CPPHEG case models the proposed Clean Power Plan using the AEO2015 High Economic Growth case as the baseline.
Policy with High Oil and Gas Resource (CPPHOGR)	The CPPHOGR case models the proposed Clean Power Plan using the AEO2015 High Oil and Gas Resource case as the baseline.

[26] See Table 17 for a list of additional sensitivity scenarios.

FIGURES IN THIS REPORT:

This report includes two primary figure styles. Difference-type figures, such as Figure 3 below, focus on the change in a specific year or over a specific time period between Clean Power Plan cases and the baseline cases from which they are developed.

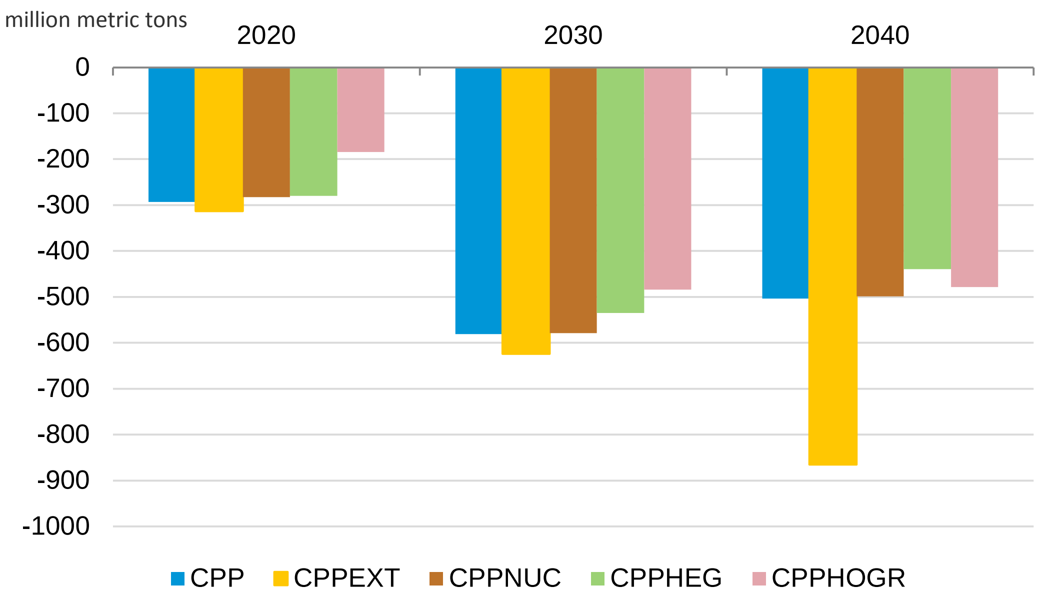
Time-trend figures, such as Figure 9 below, present base and policy case information starting from the historical year 2005 through 2040, the end of the AEO2015 projection period. Nearly all time-trend figures in this report have two panels. The left-hand panel reports the AEO Reference case (black line) together with several Clean Power Plan cases developed from that baseline. The right-hand panel reports two alternative baselines, High Economic Growth and High Oil and Gas Resources, along with one Clean Power Plan case developed from each respective baseline. Each baseline and its associated policy case in the right-hand panel use the same color (darker for the former, lighter for the latter) to help readers identify which lines should be compared to identify changes resulting from the Clean Power Plan.

Summary of Results

Power sector CO_2 emissions declined by 363 million metric tons between 2005 and 2013, due to a decline in coal's generation share and growing use of natural gas and renewables, but the CO_2 emissions are projected to change only modestly from 2013 through 2040 in the 3 baseline cases used in this report. Relative to the AEO2015 Reference case, the projected emissions trajectory is somewhat lower in the High Oil and Gas Resource case baseline, which has cheaper natural gas, and somewhat higher in the High Economic Growth case, which has higher electricity use.

The proposed Clean Power Plan would reduce projected power sector CO_2 emissions (Figure 3, Table 3 and Table 4). Reductions in projected emissions in 2030 relative to baseline projections for that year range from 484 to 625 million metric tons. The projected power sector emissions level in 2030 ranges from 1,553 to 1,727 million metric tons across the cases, reflecting a reduction of between 29% and 36% relative to the 2005 emissions level of 2,416 million metric tons.

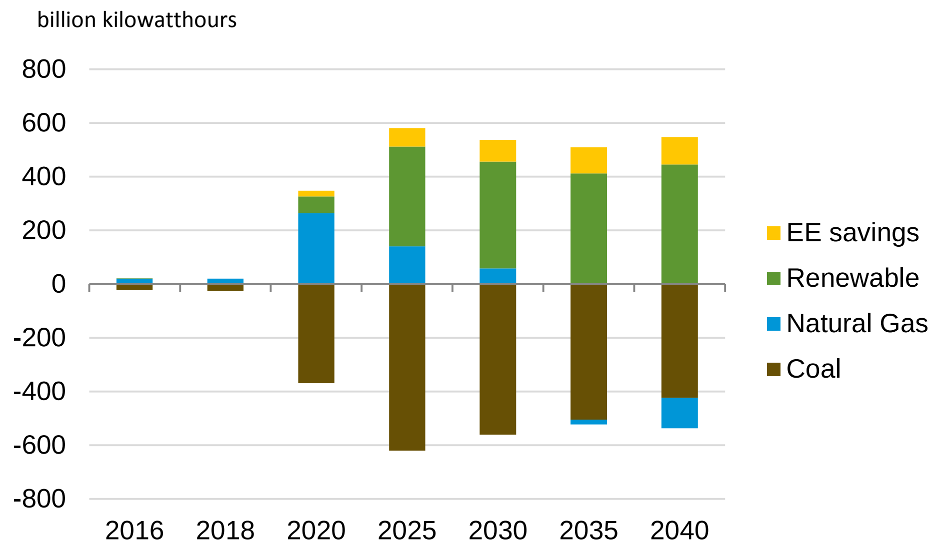
Figure 3. Change in electric power sector CO_2 emissions in Clean Power Plan (CPP) cases relative to baseline, selected years



Source: U.S. Energy Information Administration.

Switching from coal-fired generation to natural gas-fired generation is the predominant compliance strategy as implementation begins, with renewables playing a growing role in the mid-2020s and beyond (Figures 4 and 5; Tables 3 and 4). Demand-side energy efficiency plays a moderate role in compliance, relative to the early role of natural gas and the eventual role of renewables. The economics of increased natural gas generation and expanded renewable electricity capacity vary regionally, the key determinants being: 1) the natural gas supply and combined cycle utilization rates by region; and 2) the potential for penetration of renewable generation in regions including states that have no (or low) renewable portfolio standards.

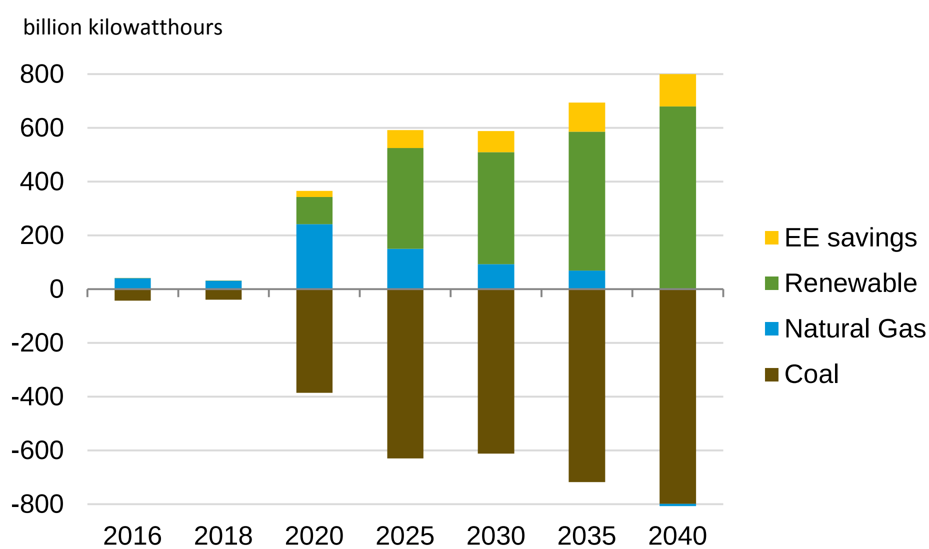
Figure 4. Change in generation and energy efficiency savings under the Clean Power Plan Base Policy case relative to AEO2015 Reference case



Source: U.S. Energy Information Administration.

With continued Clean Power Plan emissions reduction requirements through 2040 under the Policy Extension Case (CPPEXT), the shift to higher natural gas-fired generation is maintained through 2030-35 (Figure 5 and Table 3).

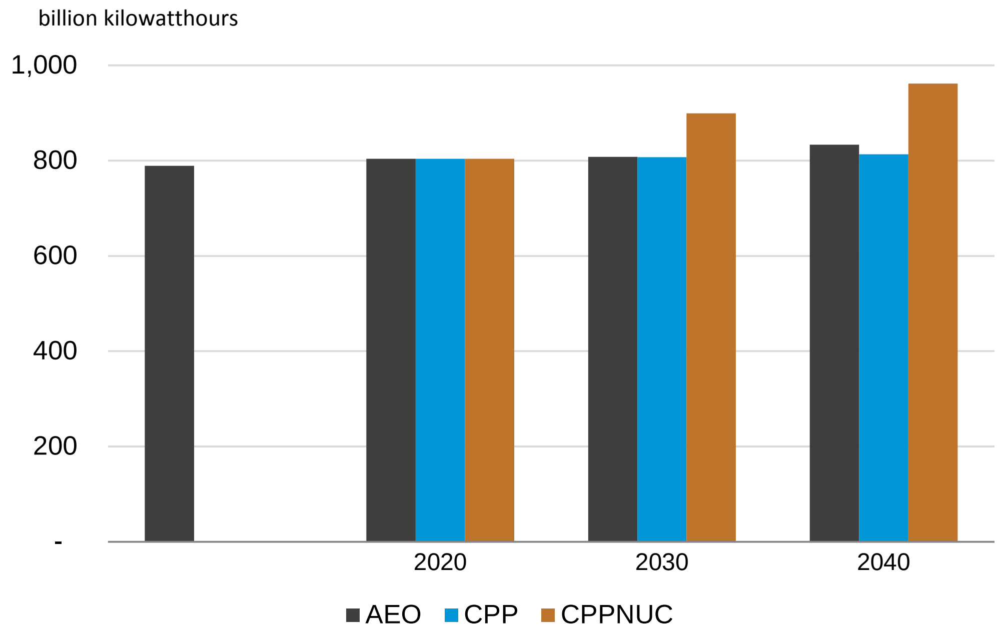
Figure 5. Change in generation and energy efficiency savings under the Clean Power Plan Policy Extension case relative to AEO2015 Reference case



Source: U.S. Energy Information Administration.

If new nuclear power generation were to be treated in the same manner as new renewable generation in compliance calculations, the Clean Power Plan would also result in increased nuclear generation (Figure 6 and Table 3).

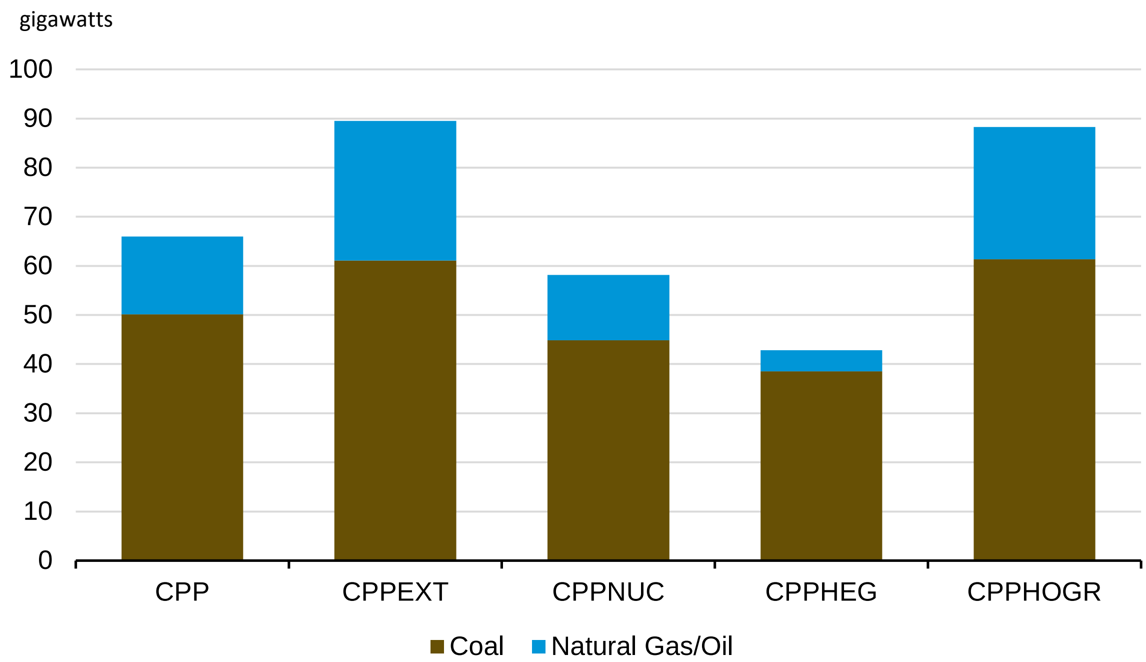
Figure 6. Nuclear generation in AEO2015 Reference and Clean Power Plan cases, selected years



Source: U.S. Energy Information Administration.

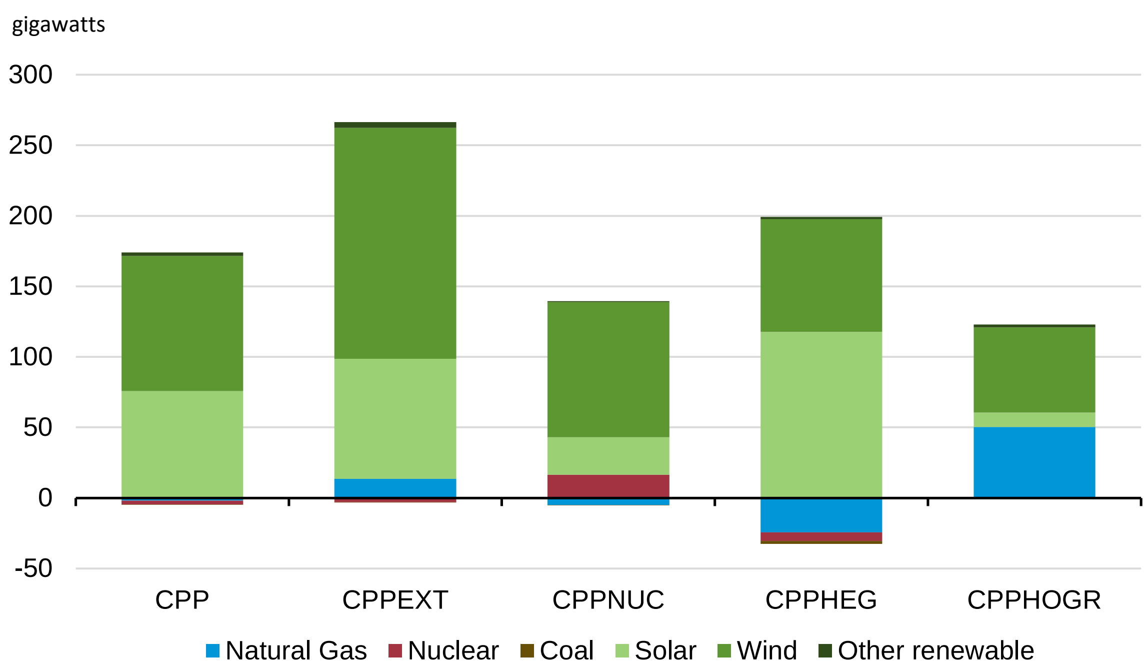
The Clean Power Plan has a significant effect on projected retirements and additions of electric generation capacity (Figures 7 and 8; Tables 3 and 4). Projected coal plant retirements over the 2014-40 period, which are 40 GW in the AEO2015 Reference case (most before 2017), increase to 90 GW (nearly all by 2020) in the Base Policy case (CPP). Retirements of inefficient units fueled by natural gas or oil, generally involving primary steam cycles, are also projected to rise. Turning to additions, which are dominated by natural gas and renewables over the 2014-40 period in the AEO2015 Reference case, the Clean Power Plan significantly increases projected renewable capacity additions in all cases. Under favorable natural gas supply conditions, the Clean Power Plan also increases additions of generation capacity fueled by natural gas (CPPHOGR). Nuclear capacity is also added in a sensitivity case in which new nuclear generation receives the same treatment as new renewable generation in compliance calculations (CPPNUC).

Figure 7. Change in generating capacity retirements by fuel type in Clean Power Plan cases relative to baseline (cumulative, 2014-40)



Source: U.S. Energy Information Administration.

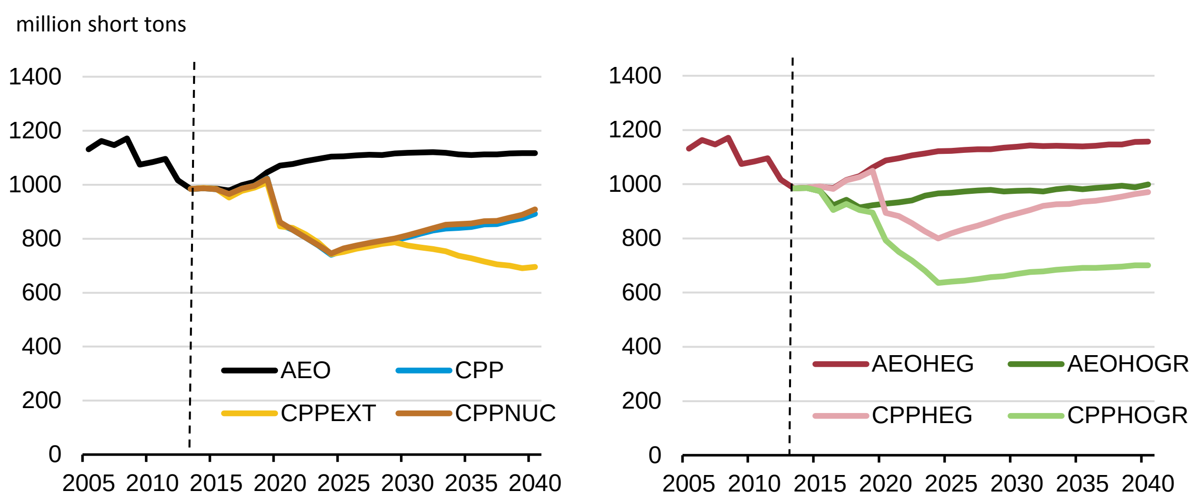
Figure 8. Change in generating capacity additions by fuel type in Clean Power Plan cases relative to baseline (cumulative, 2014-40)



Source: U.S. Energy Information Administration.

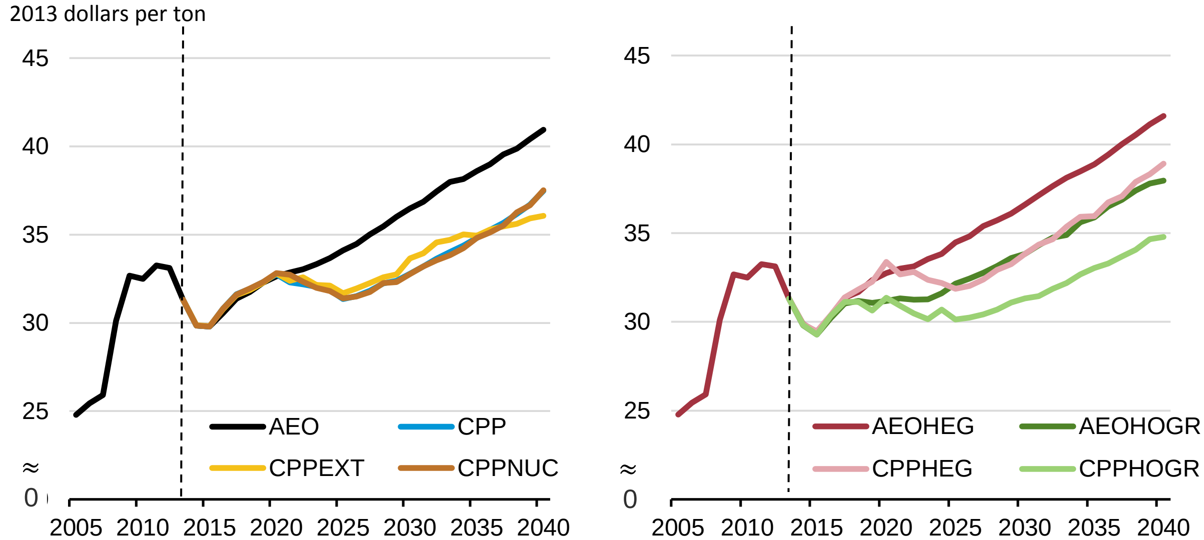
Coal production and minemouth steam coal prices are lower compared with the AEO2015 Reference case in the early years following Clean Power Plan implementation (Figures 9 and 10, and Tables 3 and 4). In the Base Policy case (CPP) projected U.S. coal production in 2020 and 2025 is 20% and 32% lower relative to the AEO2015 baseline level in those years, respectively. All major coal-producing regions (West, Interior, and Appalachia) experience negative production impacts in 2020. Expanded generation from renewables, rising natural gas prices, and static CPP targets in the post-2030 period in the CPP case allow existing coal-fired plants to operate at a higher utilization rate which rises from a low of 60% in 2024 to 71% in 2040. As a result, coal production edges higher but still remains 20% below the AEO2015 Reference case level in 2040. The Interior coal-producing region, which primarily includes the Illinois and Gulf-lignite Basins, and the West coal-producing region, which primarily includes the Powder River, Rocky Mountain, Arizona/New Mexico and Dakota-lignite Basins, account for most of the increase in production levels in the CPP case towards the end of the projection period. Average minemouth steam coal prices also decline after 2020 and are 8% and 10% lower in 2025 and 2030, respectively in the Base Policy Case compared with the AEO2015 Reference case and then remain at least 8% lower than the Reference case through 2040.

Figure 9. Total U.S. coal production in baseline and Clean Power Plan cases, 2005-40



Source: U.S. Energy Information Administration.

Figure 10. Minemouth steam coal prices in baseline and Clean Power Plan cases, 2005-40

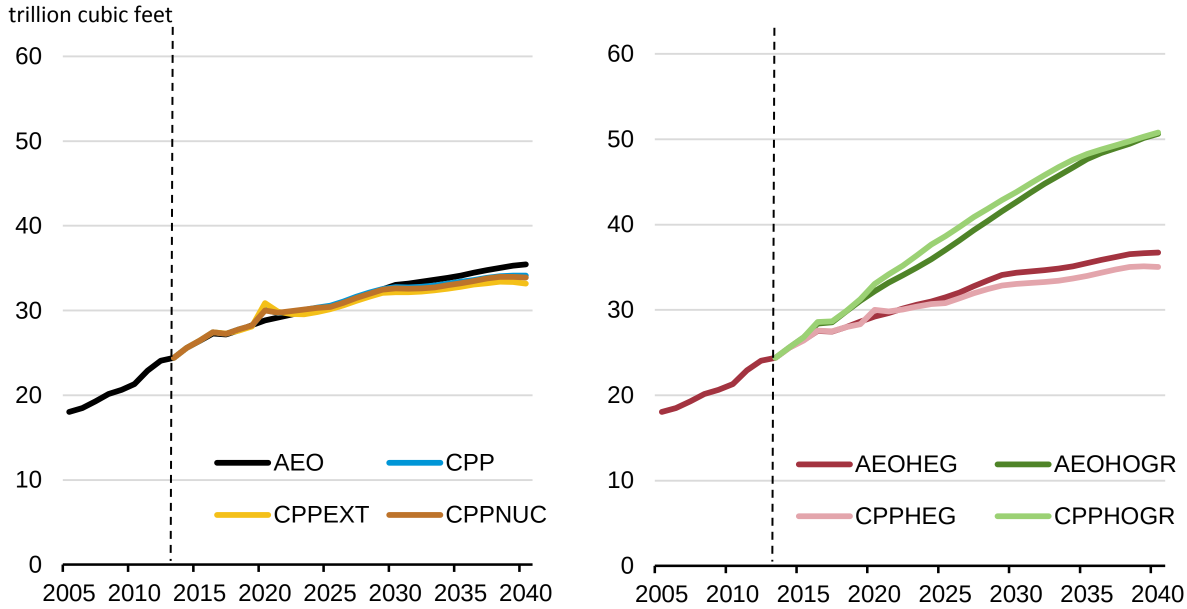


Note: Minemouth steam coal prices include coal delivered to all users of steam coal (buildings, industrial, and electricity sectors as well as steam exports).

Source: U.S. Energy Information Administration.

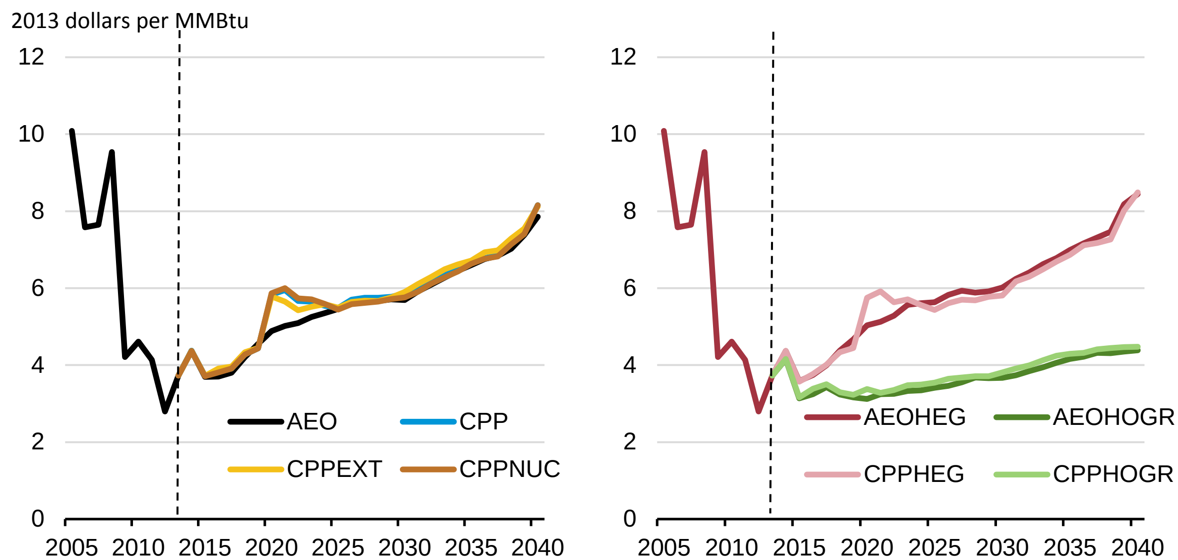
The Clean Power Plan's effect on natural gas production and prices is very sensitive to baseline supply conditions (Figure 11 and Figure 12; Tables 3 and 4). The Clean Power Plan increases natural gas use significantly relative to baseline at the start of Clean Power Plan implementation, but this effect fades over time as renewables and efficiency programs increasingly become the dominant compliance strategies. While there are significant differences in projected natural gas prices across baselines, with persistently lower prices in the High Oil and Gas Resource case, the Clean Power plan itself does not significantly move natural gas prices with the exception of an initial impact expected during the first 2-3 years after the start of implementation.

Figure 11. Natural gas production in baseline and Clean Power Plan cases, 2005-40



Source: U.S. Energy Information Administration.

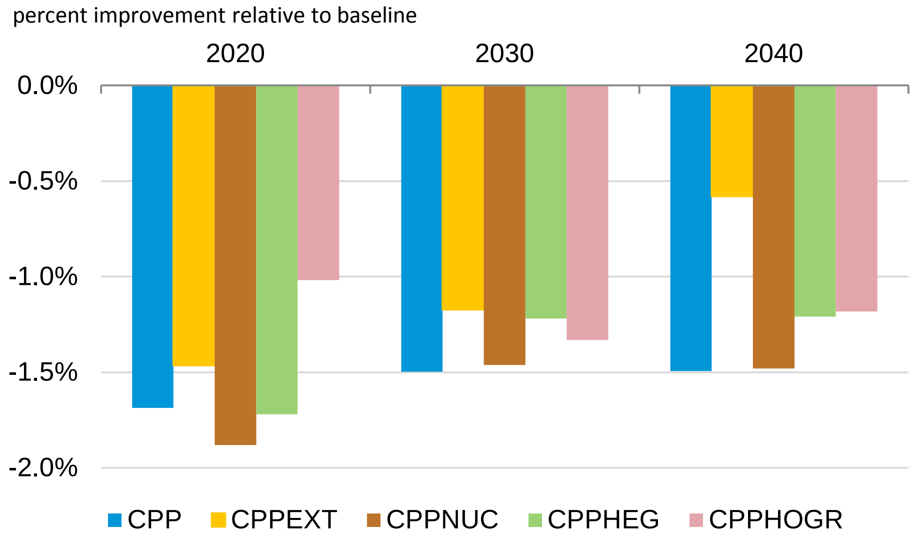
Figure 12. Henry Hub spot price for natural gas in baseline and Clean Power Plan cases, 2005-40



Source: U.S. Energy Information Administration.

Heat rates for coal-fired generators that remain in use, defined as the energy content of coal consumed (in Btu) per kWh of net electricity generated, improve modestly under the Clean Power Plan (Figure 13). In all cases, the average heat rate improvement across the fleet of coal-fired generators is less than 2%. The projected level of heat rate improvement is sensitive to assumptions about natural gas supply that influence natural gas prices, reflecting competition between available compliance options.

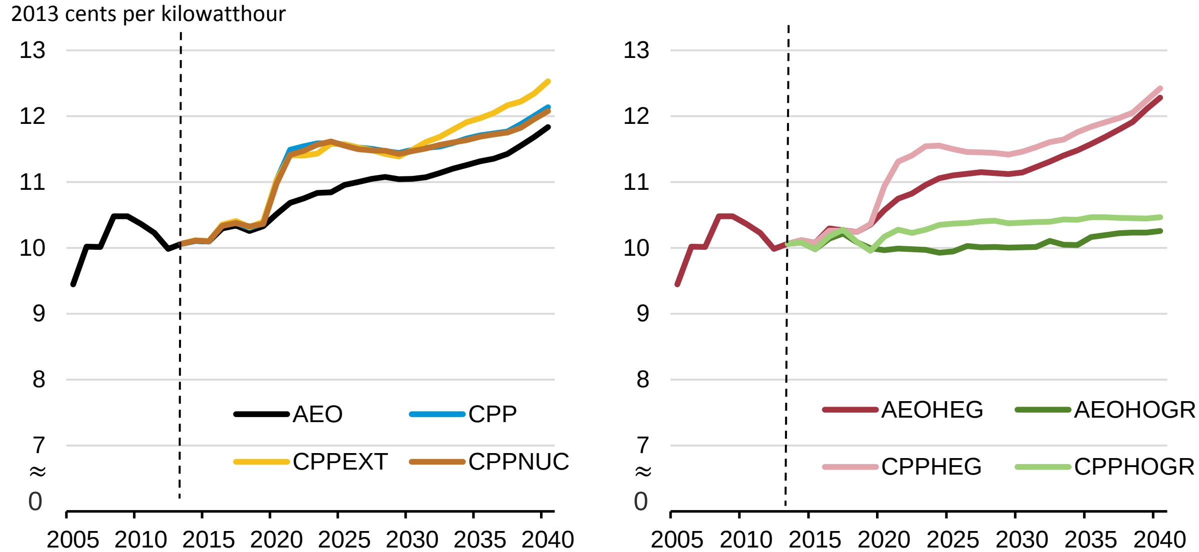
Figure 13. Average percentage change in heat rate of coal-fired generators in Clean Power Plan cases, relative to baseline cases



Source: U.S. Energy Information Administration.

Retail electricity prices and expenditures rise under the Clean Power Plan. Retail electricity prices increase most in the early 2020s, in response to initial compliance measures. Increased investment in new generating capacity as well as increased use of natural gas for generation lead to electricity prices that are 3% to 7% higher on average from 2020-25 in the Clean Power Plan cases, versus the respective baseline cases (Figure 14). While prices return to near-baseline levels by 2030 in many regions, prices remain at elevated levels in some parts of the country. In Florida and the Southeast, the Southern Plains, and the Southwest regions the projected electricity prices in 2030 are roughly 10% above baseline in the Base Policy case (CPP). Electricity expenditures also generally rise with Clean Power Plan implementation, but expenditure changes are smaller in percentage terms than price changes as the combination of energy-efficiency programs pursued for compliance purposes and higher electricity prices tends to reduce electricity consumption relative to baseline. By 2040, total electricity expenditures in the CPP case are slightly below those in the AEO2015 Reference case, as decreases in demand more than offset the price increases.

Figure 14. All sectors average retail electricity price in baseline and Clean Power Plan cases, 2005-40



Source: U.S. Energy Information Administration.

Biomass generation accounts for only a small share of total generation with or without the Clean Power Plan. Implementation of the Clean Power Plan can either increase or decrease projected biomass generation depending on the emission rate applied to biomass generation in the compliance calculation. Using the 195 pounds/MMBtu emissions rate for biomass assumed in EPA's Regulatory Impact Analysis, as in the CPPBIO195 case, EIA projects that biomass generation in 2020 and 2030 would be 33% and 71% below the respective AEO2015 baseline levels of 24 billion kWh (BkWh) and 41 BkWh for those years. In the Base Policy case (CPP), which uses the standard EIA treatment of biomass generation as a net zero emissions generation source, EIA projects that biomass generation in 2020 and 2030 would be 46% above and 5% below the respective AEO2015 baseline levels for those years.

Economic activity indicators, including real gross domestic product (GDP), industrial shipments, and consumption, are reduced relative to baseline under the Clean Power Plan. Across cases that start from the AEO2015 Reference case, the reduction in cumulative GDP over 2015-40 ranges from 0.17%-0.25%, with the high end reflecting a tighter policy beyond 2030. Implementing the Clean Power Plan under baselines that assume high economic growth or high oil and gas resources ameliorate both GDP and disposable income impacts relative to outcomes using the AEO2015 Reference case baseline.

Table 3. Summary results for AEO2015 Reference case and Clean Power Plan cases, selected years

	2005	2013	2020				2030				2040			
			AEO	CPP	CPPEXT	CPPNUC	AEO	CPP	CPPEXT	CPPNUC	AEO	CPP	CPPEXT	CPPNUC
ELECTRIC GENERATION (billion kWh)														
Coal	2,013	1,586	1,709	1,340	1,324	1,357	1,713	1,153	1,101	1,165	1,702	1,278	904	1,306
Natural Gas	761	1,118	1,117	1,382	1,359	1,371	1,371	1,429	1,464	1,401	1,569	1,456	1,560	1,400
Nuclear	782	789	804	804	804	804	808	808	808	900	833	813	811	962
Hydro	270	267	292	295	296	295	295	299	298	298	297	300	301	299
Wind	18	168	232	272	313	269	245	562	575	548	319	602	812	604
Solar	1	19	51	60	60	60	71	148	151	96	110	275	292	171
Other renewables	69	76	104	114	112	114	146	146	148	138	183	178	184	166
Oil/ other	142	47	43	41	41	41	43	40	40	40	43	41	39	41
Total	4,055	4,070	4,351	4,308	4,308	4,311	4,691	4,584	4,586	4,586	5,056	4,942	4,903	4,948
ELECTRIC GENERATION CAPACITY (GW)														
Coal	313	304	263	217	210	222	260	209	200	214	260	209	197	214
Natural gas / Oil	442	470	482	490	491	490	519	518	528	521	595	579	582	578
Nuclear	100	99	101	101	101	101	102	101	101	113	105	102	102	121
Hydro	78	79	80	80	80	80	80	81	81	81	80	81	81	81
Wind	9	61	83	100	114	99	87	192	198	188	110	205	273	206
Solar	0	13	28	32	32	32	39	76	77	51	61	136	146	87
Other renewables	12	15	17	18	18	18	20	23	23	22	24	26	28	25
Other	24	25	26	26	26	26	26	26	26	26	26	26	26	26
Total	978	1,065	1,079	1,065	1,074	1,068	1,133	1,226	1,235	1,215	1,261	1,365	1,435	1,337
ELECTRICITY-RELATED CARBON DIOXIDE EMISSIONS (million metric tons)														
Power sector	2,416	2,053	2,107	1,814	1,794	1,825	2,177	1,596	1,553	1,598	2,195	1,691	1,329	1,696
ELECTRICITY PRICES (2013 cents per kWh)														
Residential	11.0	12.2	12.9	13.5	13.5	13.4	13.6	14.2	14.2	14.2	14.5	14.9	15.3	14.8
Commercial	10.1	10.1	10.6	11.1	11.1	11.1	11.1	11.5	11.5	11.5	11.8	12.1	12.5	12.1
Industrial	6.6	6.9	7.3	7.7	7.7	7.7	7.7	8.0	8.1	8.0	8.4	8.6	9.0	8.5
All Sectors[1]	9.4	10.1	10.5	11.0	11.0	11.0	11.1	11.5	11.5	11.5	11.8	12.1	12.5	12.1
ELECTRICITY EXPENDITURES (billion 2013 dollars)														
Residential	149.0	169.2	183.6	189.8	189.8	189.2	202.9	205.8	205.9	205.7	229.9	230.6	235.0	229.7
Commercial	128.3	135.7	150.1	155.9	156.1	155.4	169.2	170.9	170.8	170.7	195.4	192.8	196.7	192.1
Industrial	67.8	65.8	79.6	83.3	83.1	82.8	91.2	92.7	92.9	92.6	101.5	101.7	105.3	101.3
Total[2]	345.1	370.7	413.3	429.1	429.0	427.4	463.3	469.4	469.5	469.0	526.7	525.1	537.0	523.1
ENERGY PRODUCTION (quadrillion Btu)														
Natural Gas	18.6	25.1	29.6	30.9	30.7	30.8	33.9	33.6	33.5	33.5	36.4	35.0	35.2	34.8
Coal	23.2	20.0	21.7	17.6	17.4	17.7	22.5	16.6	16.1	16.7	22.6	18.3	14.6	18.6
Oil	13.3	19.2	27.7	27.7	27.7	27.7	26.8	26.8	26.8	26.7	25.4	25.4	25.5	25.4
Nuclear	8.2	8.3	8.4	8.4	8.4	8.4	8.5	8.5	8.5	9.4	8.7	8.5	8.5	10.1
Renewable	6.2	9.0	10.4	11.0	11.4	11.0	11.0	14.8	15.0	14.1	12.5	16.7	18.9	15.5
Other	0.0	1.3	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	1.0	0.9	0.9	0.9
Total	69.4	82.7	98.7	96.5	96.5	96.5	103.7	101.2	100.7	101.4	106.6	104.9	103.6	105.4

Table 3. Summary results for AEO2015 Reference case and Clean Power Plan cases, selected years (cont.)

	2005	2013	2020				2030				2040			
			AEO	CPP	CPPEXT	CPPNUC	AEO	CPP	CPPEXT	CPPNUC	AEO	CPP	CPPEXT	CPPNUC
OTHER PRICES (2013 $/MMBtu, unless otherwise noted)														
Natural Gas (Henry Hub)	10.08	3.73	4.88	5.83	5.78	5.80	5.69	5.86	5.90	5.82	7.85	8.15	8.12	8.11
Average Delivered Natural Gas Price to Electric Power Sector	9.55	4.40	5.39	6.47	6.36	6.41	6.22	6.38	6.41	6.29	8.28	8.32	8.33	8.13
Steam Coal Minemouth Price (2013$/short-ton)	24.79	31.31	32.64	32.75	32.80	32.82	36.49	32.78	33.65	32.77	40.94	37.48	36.06	37.51
Steam Coal Price Delivered to Electric Power Sector	1.79	2.34	2.38	2.29	2.29	2.30	2.67	2.33	2.32	2.32	2.92	2.61	2.41	2.63
Brent Spot Price (2013 dollars per barrel)	63.32	108.64	79.13	79.09	79.10	79.09	105.64	105.64	105.64	105.64	141.28	141.31	141.47	141.46
ECONOMIC INDICATORS (billion 2009 chain-weighted dollars, unless otherwise noted)														
Gross domestic product	14,234	15,710	18,801	18,739	18,732	18,744	23,894	23,866	23,855	23,862	29,898	29,886	29,831	29,899
Total industrial shipments	7,464	7,004	8,467	8,423	8,417	8,426	9,870	9,810	9,801	9,810	11,463	11,418	11,374	11,423
Non-farm employment (millions)	134	136	149	149	149	149	159	159	159	159	169	169	169	169
Average Annual Change in CPI from 2013 (%)	-	0.00%	1.75%	1.82%	1.83%	1.81%	1.85%	1.88%	1.88%	1.88%	1.98%	1.99%	2.00%	1.99%
END-USE ENERGY CONSUMPTION (quadrillion Btu)														
Liquids	39.1	35.6	36.9	36.7	36.7	36.7	36.3	36.0	36.0	36.1	36.0	35.9	35.8	35.9
Natural Gas	16.6	18.5	19.0	18.9	18.9	18.9	19.8	19.7	19.6	19.7	20.9	20.7	20.7	20.8
Electricity	12.5	12.6	13.4	13.3	13.3	13.3	14.3	14.0	14.0	14.0	15.3	14.8	14.7	14.8
Coal	2.1	1.5	1.6	1.6	1.6	1.6	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
PRIMARY ENERGY (quadrillion Btu)														
Consumption	100.2	97.1	100.8	99.0	99.0	99.0	102.9	100.4	100.2	100.6	105.7	104.0	102.7	104.4
Imports	34.7	24.5	20.2	20.2	20.1	20.2	21.7	21.3	21.3	21.3	24.1	23.7	23.5	23.7
Exports	4.5	11.7	18.1	17.7	17.7	17.8	22.4	21.9	21.7	21.9	24.6	24.3	24.1	24.4
Production	69.4	82.7	98.7	96.5	96.5	96.5	103.7	101.2	100.7	101.4	106.6	104.9	103.6	105.4

[1]All sector average price includes transportation sector.

[2]Total expenditures exclude transportation sector.

Source: U.S. Energy Information Administration.

Table 4. Summary results for AEO2015 High Oil and Gas Resource, High Economic Growth and CPP cases, selected years

	2005	2013	2020				2030				2040			
			AEO HOGR	CPP HOGR	AEO HEG	CPP HEG	AEO HOGR	CPP HOGR	AEO HEG	CPP HEG	AEO HOGR	CPP HOGR	AEO HEG	CPP HEG
ELECTRIC GENERATION (billion kWh)														
Coal	2,013	1,586	1,443	1,212	1,733	1,415	1,441	898	1,733	1,293	1,440	910	1,744	1,421
Natural Gas	761	1,118	1,450	1,610	1,204	1,377	1,832	2,092	1,573	1,422	2,200	2,439	1,705	1,475
Nuclear	782	789	804	804	804	804	808	808	818	808	808	808	911	863
Hydro	270	267	289	294	294	305	290	295	297	305	290	295	298	308
Wind	18	168	229	263	243	315	232	407	301	634	234	412	489	725
Solar	1	19	51	59	52	70	65	85	80	247	85	106	160	420
Other renewables	69	76	107	110	106	117	146	128	158	161	175	145	222	207
Oil/ other	142	47	44	41	43	42	42	39	43	41	42	40	43	42
Total	4,055	4,070	4,417	4,392	4,480	4,445	4,854	4,753	5,003	4,912	5,274	5,154	5,574	5,461
ELECTRIC GENERATION CAPACITY (GW)														
Coal	313	304	245	201	265	230	242	173	263	223	242	173	264	223
Natural gas / Oil	442	470	497	516	490	497	573	607	564	540	674	704	657	629
Nuclear	100	99	101	101	101	101	101	101	103	102	101	101	115	109
Hydro	78	79	79	80	80	82	79	80	80	82	79	80	81	83
Wind	9	61	82	97	87	115	83	142	105	216	84	144	165	245
Solar	0	13	27	32	28	38	36	45	44	121	48	58	82	200
Other renewables	12	15	17	18	18	19	20	21	23	26	22	23	32	31
Other	24	25	26	26	26	26	26	26	26	26	26	26	26	26
Total	978	1,065	1,075	1,070	1,094	1,108	1,159	1,196	1,207	1,335	1,275	1,309	1,422	1,546
ELECTRICITY-RELATED CARBON DIOXIDE EMISSIONS (million metric tons)														
Power sector	2,416	2,053	1,973	1,789	2,165	1,886	2,089	1,605	2,262	1,727	2,179	1,701	2,266	1,827
ELECTRICITY PRICES (2013 cents per kWh)														
Residential	11.0	12.2	12.3	12.6	12.9	13.4	12.6	13.1	13.7	14.1	12.8	13.1	14.9	15.1
Commercial	10.1	10.1	10.1	10.3	10.8	11.1	10.0	10.4	11.3	11.6	10.2	10.4	12.4	12.6
Industrial	6.6	6.9	6.8	7.0	7.4	7.7	6.8	7.1	7.9	8.1	7.1	7.2	8.9	8.9
All Sectors[1]	9.4	10.1	10.0	10.2	10.6	10.9	10.0	10.4	11.1	11.5	10.3	10.5	12.3	12.4
ELECTRICITY EXPENDITURES (billion 2013 dollars)														
Residential	149	169	177	179	190	194	192	194	220	222	211	211	265	264
Commercial	128	136	144	146	153	156	156	158	174	175	174	172	209	205
Industrial	68	66	76	78	86	89	86	88	104	105	90	91	127	126
Total[2]	345	371	397	403	428	439	434	440	498	502	475	473	602	594
ENERGY PRODUCTION (quadrillion Btu)														
Natural Gas	18.6	25.1	33.1	34.0	30.0	30.8	43.8	45.0	35.3	33.9	52.0	52.2	37.7	36.0
Coal	23.2	20.0	18.8	16.3	22.0	18.4	19.8	14.0	23.0	18.3	20.3	14.7	23.5	20.0
Oil	13.3	19.2	32.6	32.6	27.7	27.7	40.5	40.5	27.1	27.0	43.6	43.3	26.0	25.8
Nuclear	8.2	8.3	8.4	8.4	8.4	8.4	8.5	8.5	8.6	8.5	8.5	8.5	9.5	9.0
Renewable	6.2	9.0	10.4	10.9	10.7	11.8	10.9	12.6	12.0	16.9	11.4	13.0	15.5	20.1
Other	0.0	1.3	0.9	0.9	0.9	0.9	1.0	1.0	1.0	0.9	1.0	1.0	1.0	1.0
Total	69.4	82.7	104.3	103.1	99.7	98.1	124.4	121.6	107.0	105.6	136.8	132.7	113.3	111.9

Table 4. Summary results for AEO2015 High Oil and Gas Resource, High Economic Growth and CPP cases, selected years (cont.)

	2005	2013	2020				2030				2040			
			AEO HOGR	CPP HOGR	AEO HEG	CPP HEG	AEO HOGR	CPP HOGR	AEO HEG	CPP HEG	AEO HOGR	CPP HOGR	AEO HEG	CPP HEG
OTHER PRICES (2013 $/MMBtu, unless otherwise noted)														
Natural Gas (Henry Hub)	10.08	3.73	3.12	3.38	5.03	5.75	3.67	3.81	6.02	5.81	4.38	4.47	8.45	8.49
Average Delivered Natural Gas Price to Electric Power Sector	9.55	4.40	3.68	4.07	5.65	6.34	4.15	4.27	6.61	6.31	4.67	4.86	8.71	8.57
Steam Coal Minemouth Price (2013$/short-ton)	24.79	31.31	31.18	31.37	32.74	33.37	33.82	31.32	36.61	33.83	37.96	34.78	41.60	38.92
Steam Coal Price Delivered to Electric Power Sector	1.79	2.34	2.24	2.18	2.39	2.33	2.44	2.12	2.68	2.41	2.67	2.30	2.96	2.73
Brent Spot Price (2013 dollars per barrel)	63.32	108.64	75.72	75.40	79.67	79.62	98.15	97.99	107.51	107.24	129.38	129.52	145.17	144.91
ECONOMIC INDICATORS (billion 2009 chain-weighted dollars, unless otherwise noted)														
Gross domestic product	14,234	15,710	18,841	18,796	19,590	19,526	24,222	24,192	26,146	26,126	30,236	30,186	34,146	34,107
Total industrial shipments	7,464	7,004	8,566	8,536	8,967	8,924	10,349	10,314	11,081	11,022	11,989	11,969	13,786	13,656
Non-farm employment (millions)	134	136	149	149	152	152	160	160	166	166	170	170	176	176
Average Annual Change in CPI from 2013 (%)	-	0.00%	1.56%	1.60%	1.67%	1.74%	1.63%	1.63%	1.62%	1.65%	1.85%	1.84%	1.80%	1.82%
END-USE ENERGY CONSUMPTION (quadrillion Btu)														
Liquids	39.1	35.6	37.4	37.3	37.8	37.6	37.7	37.4	38.3	38.2	37.4	37.3	39.7	39.4
Natural Gas	16.6	18.5	19.8	19.7	19.2	19.1	21.9	21.9	20.6	20.6	24.1	24.0	22.5	22.4
Electricity	12.5	12.6	13.6	13.6	13.8	13.7	14.8	14.5	15.3	15.0	15.9	15.5	16.8	16.4
Coal	2.1	1.5	1.6	1.6	1.7	1.7	1.6	1.5	1.8	1.8	1.5	1.5	1.9	1.9
PRIMARY ENERGY (quadrillion Btu)														
Consumption	100.2	97.1	101.8	100.6	103.1	101.6	106.8	103.7	108.5	107.2	110.8	107.7	116.2	114.9
Imports	34.7	24.5	19.9	20.4	21.0	20.9	18.2	18.0	23.5	23.2	18.3	18.4	27.3	26.9
Exports	4.5	11.7	22.5	23.0	17.7	17.4	35.7	35.8	21.7	21.4	44.0	43.2	23.9	23.5
Production	69.4	82.7	104.3	103.1	99.7	98.1	124.4	121.6	107.0	105.6	136.8	132.7	113.3	111.9

[1] All sector average price includes transportation sector.
[2] Total expenditures exclude transportation sector.

Source: U.S. Energy Information Administration.

Detailed Results

Appendices G, H and I provide sets of tables that summarize key results for all cases included in this report for 2020, 2030, and 2040.

EIA's standard reporting tables for all runs in this study are available through the AEO web browser at http://www.eia.gov/beta/aeo.

CO_2 emissions and compliance strategy indicators

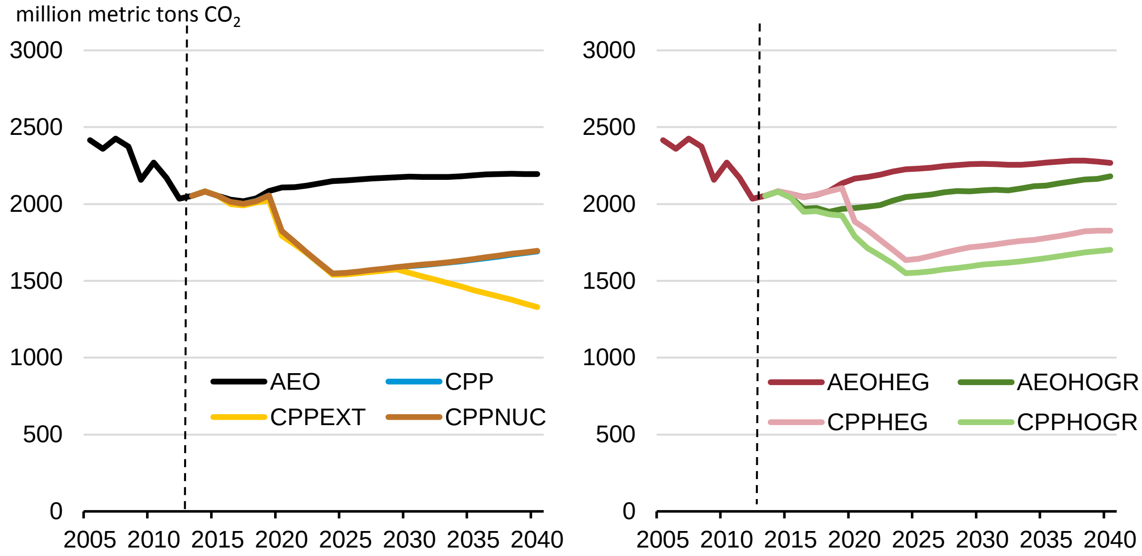
CO_2 emissions

In the AEO2015 Reference case (AEO), EIA projects that power sector CO_2 emissions will fall below 2005 levels by 13% in 2020, by 10% in 2030 and 9% in 2040. The expected reductions in CO_2 emissions are primarily due to moderate natural gas prices, which result in higher utilization of natural gas-fired generating capacity and lower use of coal-fired generators, along with renewable energy standards, which lead to increased generation from zero-carbon technologies.

EIA projects that the Clean Power Plan would further reduce power sector CO_2 emissions through a combination of compliance strategies, including re-dispatch, increasing use of lower-carbon technologies, heat rate improvements, and energy efficiency. The projected reductions are sensitive to many factors, especially assumptions about economic growth, fuel prices, and post-2030 policies.

Figure 15 compares total electric power sector CO_2 emissions across the Clean Power Plan cases and baseline cases. In the Base Policy case (CPP), power sector CO_2 emissions are 25% below 2005 levels in 2020 and about 34% below 2005 levels in 2030. By 2040, the corresponding reduction is 30%, as continued demand growth leads to additional generation from fossil fuel-fired sources. In the Policy Extension case (CPPEXT), the assumed decrease in the emission performance goals after 2030 results in a 45% reduction in CO_2 emissions in 2040, compared with 2005 levels.

Figure 15. Power sector CO_2 emissions in Baseline and Clean Power Plan cases, 2005-40



Source: U.S. Energy Information Administration.

Higher economic growth typically results in higher electricity demand, which in turn can lead to higher power sector CO_2 emissions. In the AEO2015 High Economic Growth case (AEOHEG), power sector CO_2 emissions are 10% below 2005 levels in 2020 and 6% below 2005 levels in 2030 and 2040. In the CPPHEG case, which applies the Clean Power Plan under the AEO2015 High Economic Growth assumptions, power sector CO_2 emissions in 2020, 2030, and 2040 are 22%, 29%, and 24% lower than 2005 levels, respectively.

Low natural gas prices can lead to lower power sector CO_2 emissions due to increased switching from coal-fired generation to less-carbon-intensive natural gas-fired generation. In the High Oil and Gas Resource case (AEOHOGR), power sector CO_2 emissions are 18% below 2005 levels in 2020, 14% below 2005 levels in 2030, and 10% below 2005 levels in 2040. In the CPPHOGR case, which applies the Clean Power Plan under AEO2015 High Oil and Gas Resource assumptions, power sector CO_2 emissions in 2020, 2030, and 2040 are 26%, 34%, and 30% lower than 2005 levels, respectively. The CPPHOGR case, which assumes conditions leading to lower natural gas prices, relies more heavily on switching from coal to natural gas, relative to the Base Policy case (CPP).

Table 5. Power sector CO_2 emissions reduction relative to 2005 levels in Clean Power Plan cases

	CPP	CPPEXT	CPPNUC	CPPHEG	CPPHOGR
2020	-25%	-26%	-24%	-22%	-26%
2030	-34%	-36%	-34%	-29%	-34%
2040	-30%	-45%	-30%	-24%	-30%

Source: U.S. Energy Information Administration.

Total generation by fuel type

In the early years of compliance, re-dispatch from coal-fired generation to natural gas-fired generation is the main strategy to achieve emission performance goals. In the longer term, growth in renewable generation provides a dominant share of compliance, reflecting both increasingly attractive costs and the design of the formula used to calculate compliance. The ultimate generation mix depends on the base assumptions regarding future natural gas prices and economic growth.

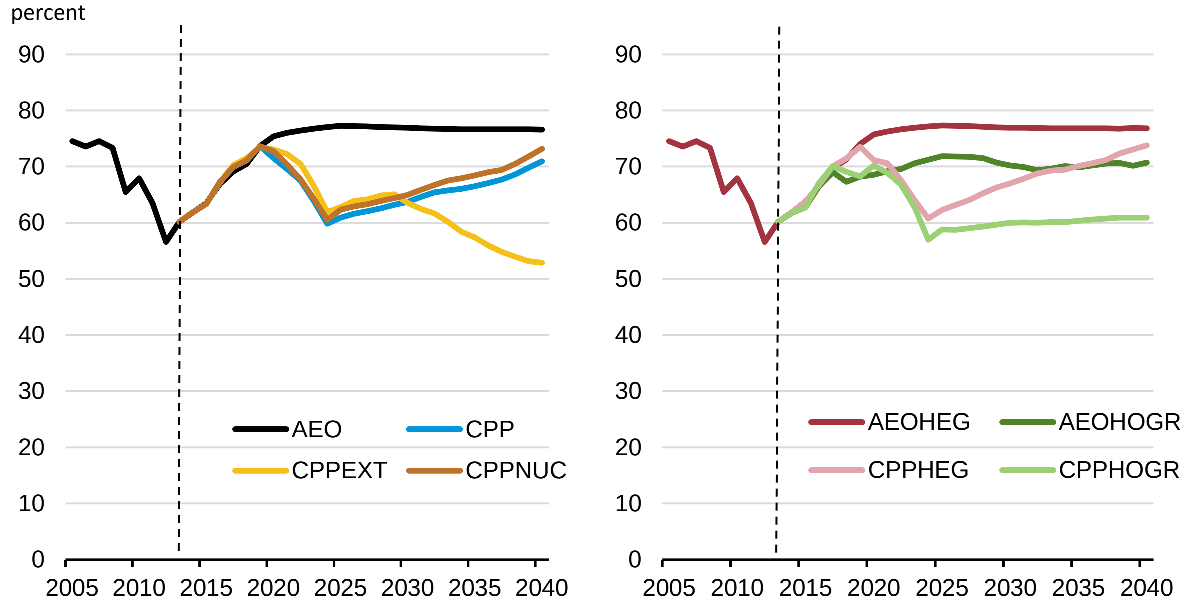
In all Clean Power Plan cases, total coal-fired generation declines from the 2013 level of 1,586 billion kilowatthours (BkWh), which is already well below the 2005 level of 2,013 BkWh. The declines relative to baseline coal-fired generation range from 18% to 43% in 2030 (Figure 18). In the Base Policy case (CPP), coal-fired generation declines to 1,340 BkWh in 2020 and 1,153 BkWh in 2030 (27% below the underlying AEO2015 Reference case baseline level). In the Policy Extension case (CPPEXT), where emission performance goals continue to decline post-2030, coal-fired generation continues to fall, to 904 BkWh in 2040.

In the CPPHEG case, coal-fired generators produce a higher level of output under higher demand growth, but carry about the same share of total generation relative to the Base Policy case. In the CPPHOGR case, lower natural gas prices result in more re-dispatch from coal-fired generation to natural gas-fired generation, with coal-fired generation declining to 898 BkWh by 2030 and remaining near that level through 2040. In the CPPHOGR case, the share of total generation from coal-fired units drops to 18% in 2040.

Capacity factor is a measure of the utilization of a generating resource’s total capacity, and is a convenient metric for analyzing re-dispatch trends under the Clean Power Plan. In the Base Policy Case, the average capacity factor for coal-fired generators decreases from 74% in 2019 to 60% in 2024, as regions adjust generator dispatch to meet interim emission performance goals (Figure 16). By 2040, the capacity factor for coal-fired generators rebounds to 71%. In the Policy Extension case, capacity factors for coal-fired generators level off following the early compliance years, averaging 66% from 2020-30, but then decline steadily to 53% by 2040.

Capacity factors for coal-fired generating units are highest among the Clean Power Plan cases under AEO2015 High Economic Growth assumptions in the CPPHEG case, rebounding from 61% in 2024 to 74% in 2040 due to higher electricity demand growth and increased use of other compliance options, which offset the carbon intensity impact of coal-fired generation. Capacity factors for coal-fired generating units are lowest in the CPPHOGR case, averaging 61% from 2020 through 2040, due to low natural gas prices in the underlying AEO2015 High Oil and Gas Resource base case.

Figure 16. Average capacity factor for coal-fired generating units in Baseline and Clean Power Plan cases, 2005-40

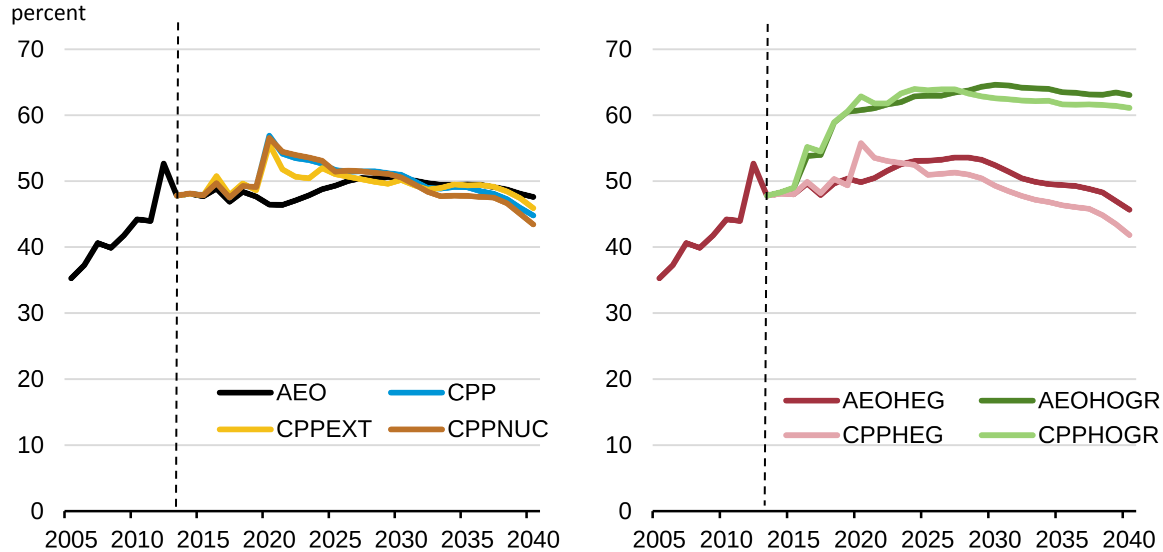


Source: U.S. Energy Information Administration.

Natural gas-fired generation increases substantially in the early 2020s across all cases, as an initial compliance strategy. Natural gas-fired generation increases from 1,118 BkWh in 2013 to 1,382 BkWh in 2020 in the Base Policy case, 24% above the underlying AEO2015 Reference case baseline level. However, by 2030, natural gas-fired generation is near its baseline Reference case levels, due to lower demand requiring less new natural gas-fired capacity and an increased reliance on renewable generation for compliance. The share of total generation from natural gas grows from 27% to 32% from 2013-20 in the Base Policy case, and remains at or above 30% throughout most of the projection. In the Policy Extension case, natural gas-fired generation continues to grow beyond 2030, displacing more coal-fired generation when emission performance goals continue to decline (become more stringent), and the natural gas share remains steady between 32% and 33% from 2031 to 2040. Only the CPPHOGR case, which uses AEO2015 High Oil and Gas Resource assumptions, sees continued growth in the share of natural gas-fired generation throughout the projection, reaching 47% in 2040, as lower natural gas prices lead to greater reliance on natural gas-fired compliance strategies over renewables.

Capacity factors for natural gas combined cycle plants experience a sharp ramp-up at the beginning of the compliance period, peaking in 2020 at 57% in the Base Policy case and 56% in the Policy Extension case, before falling to 45% and 46%, respectively, in 2040 (Figure 17). By contrast, natural gas-fired combined cycle plants have their highest capacity factors among the Clean Power Plan cases in the CPPHOGR case, averaging 62% between 2020 and 2040.

Figure 17. Average capacity factor for natural gas combined cycle plants in Baseline and Clean Power Plan cases, 2013-40



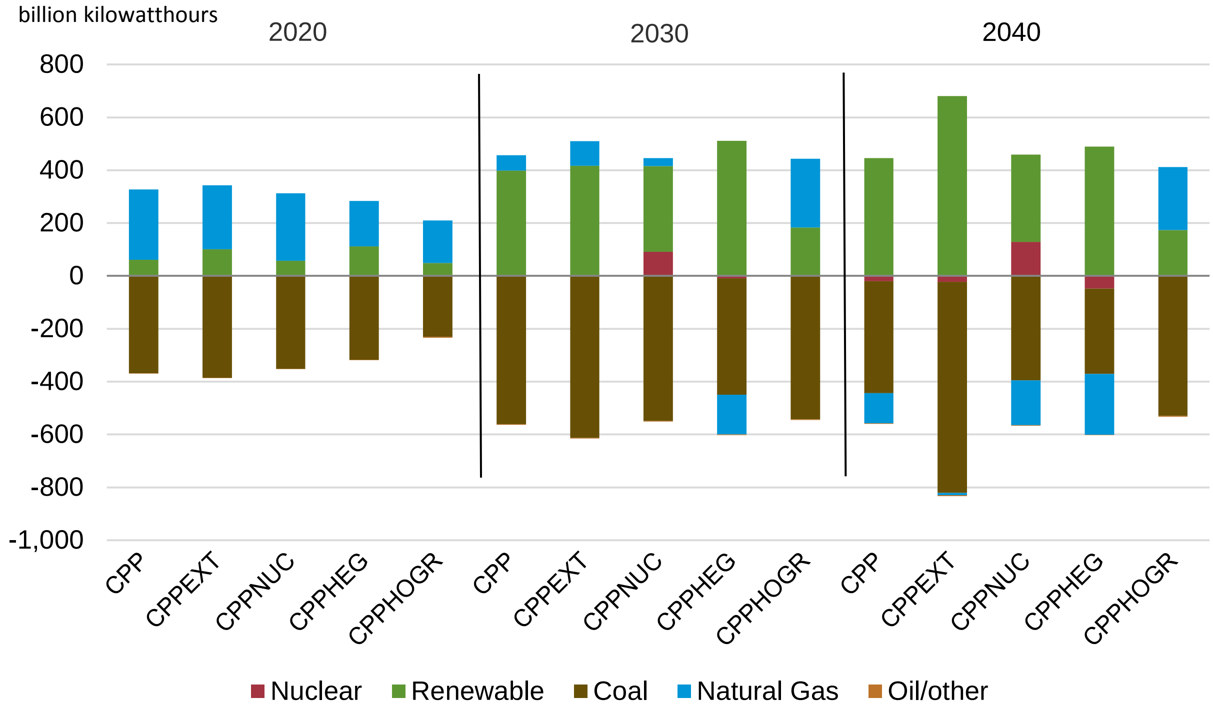
Source: U.S. Energy Information Administration.

New renewable generation represents an important strategy for attaining compliance requirements. In the Base Policy case, as emission performance goals decline (become more stringent) over the interim compliance period, renewable generation increases to 1,154 BkWh in 2030 (53% above the AEO2015 Reference case and more than double 2013 levels). The role of renewables in the compliance mix grows over time. As interim Clean Power Plan requirements begin in 2020, natural-gas fired combined cycle units predominate among the alternatives to existing coal-fired generation, with natural gas generation increasing by 369 BkWh over baseline levels, while coal generation declines by 369 BkWh. By 2025, however, renewable generation contributes more to the shifting generation mix and by 2030 the increase in renewable generation relative to the AEO is 398 BkWh, compared with a decline in coal generation of 561 BkWh.

Renewable generation continues to increase beyond 2030 in the Base Policy case, as rising natural gas prices make re-dispatch from coal to natural gas a less economically attractive compliance mechanism. In both the Policy Extension case and the CPPHEG case, renewable generation represents over 30% of total generation in 2040, with higher levels of renewable generation required to meet the declining goals, or to maintain the goals under more robust electricity demand growth, respectively.

However, the use of renewables as the primary long-term compliance mechanism is sensitive to fuel price assumptions. In the CPPHOGR case, which assumes AEO2015 High Oil and Gas Resource conditions, renewable generation represents less than 20% of total generation throughout the projection as regions tend to choose compliance strategies involving re-dispatch and displacement of existing coal-fired generation with generation from new natural gas-fired combined cycle capacity.

Figure 18. Change in electricity generation by fuel in Clean Power Plan cases relative to baseline



Source: U.S. Energy Information Administration.

Heat rate improvement

Heat rate is a measure of the thermal efficiency of a power plant, representing the amount of energy, in Btu, used to generate one kilowatthour of net electricity generation. NEMS incorporates logic that allows coal-fired generating units to undertake heat rate improvement projects, whenever it is economic to do so under baseline conditions or when the Clean Power Plan is implemented. EIA's analysis indicates that heat rate improvement activities would significantly increase under the proposed rule. Most heat rate improvement activity takes place in the early years of compliance.

In the Base Policy case, the average heat rate for coal-fired generating units reaches its most efficient point, 10,170 British thermal units per kilowatthour (Btu/kWh), in 2023 (a 1.9% improvement over the underlying baseline AEO2015 Reference case). Through the remainder of the projection, the average heat rate for coal-fired generating units rises slightly, as more non-fossil fuel generating sources come online and less-efficient coal-fired generating units achieve higher production levels without violating regional emission performance goals.

Table 6 presents average heat rates for coal-fired generating units, and the total capacity performing heat rate improvement projects, in the baseline and Clean Power Plan cases for 2020, 2030, and 2040. The reported heat rates apply to coal-fired generation fleets and utilization rates that vary considerably across cases. For this reason, differences in heat rates across cases cannot be attributed only to differences in heat rate improvement investments.

In the Base Policy case, 75 gigawatts of coal-fired capacity undertake heat rate improvement projects by 2040, compared with 13 gigawatts in the underlying baseline AEO2015 Reference case. In the Policy

Extension case, there is less heat rate improvement activity (57 gigawatts in 2040) due to a combination of factors: higher overall coal-fired generation capacity retirements, along with regional decisions to pursue other compliance options early in the projection, in anticipation of increasingly stringent post-2030 requirements.

Heat rate improvement activity is economic if the requisite capital, operations, and maintenance costs are lower than expected fuel cost savings. When natural gas prices are low, it is less costly to substitute natural gas-fired generation for coal-fired generation, and regions find it less economically attractive to use heat rate improvement as a compliance mechanism. In the CPPHOGR case, which evaluates the Clean Power Plan under lower natural gas prices using AEO2015 High Oil and Gas Resource assumptions, 43 gigawatts of capacity undertake heat rate improvement activity by 2040. This represents a 32 gigawatt increase over the underlying base case, but is nearly 42% lower than the amount of capacity undertaking heat rate improvement in the Base Policy case, and 44% lower than the amount in the CPPHEG case, which assumes AEO2015 High Economic Growth conditions.

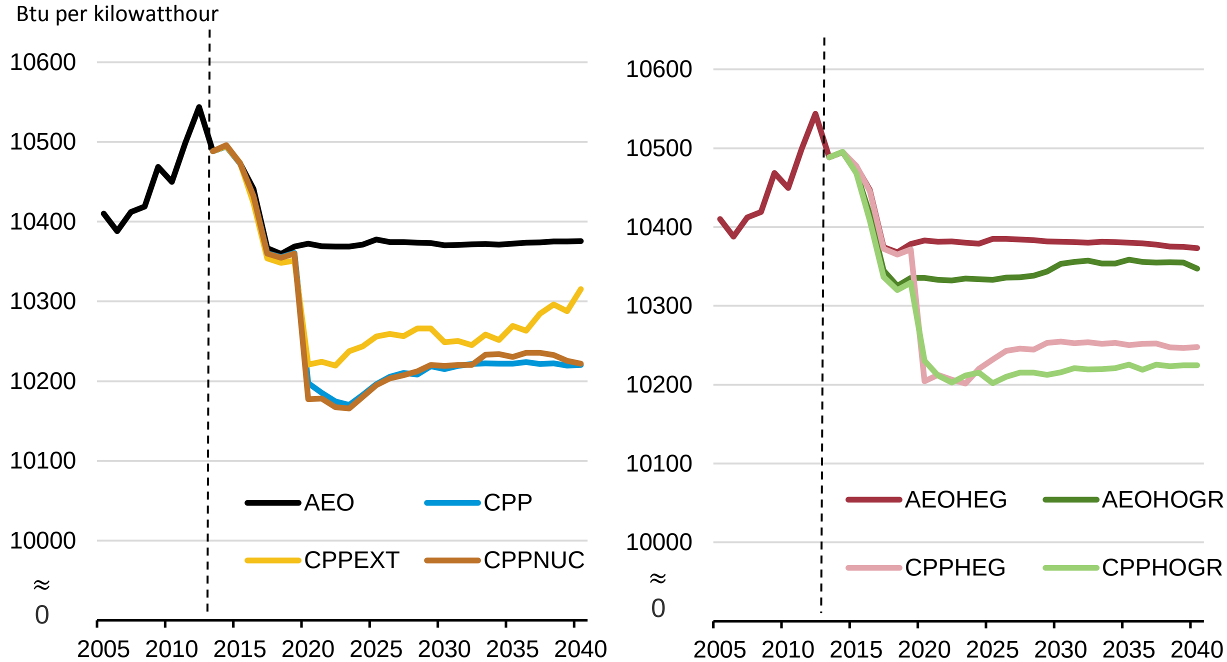
Figure 19 illustrates the average heat rate for coal-fired generators in the Clean Power Plan cases and the respective baseline cases. Across cases, the overall level of heat rate improvement is modest. Relative to baseline, the highest level of heat rate improvement occurs in the Base Policy case. Lower levels of heat rate improvement are realized when the Clean Power Plan emission performance goals are extended (Policy Extension) because other compliance options are more economic when greater reductions in the average emission rate are required.

Table 6. Summary of heat rates and capacity performing heat rate improvement in Baseline and Clean Power Plan cases

	Average heat rate for coal-fired units (Btu/kWh)			Gigawatts of capacity undertaking HRI		
Case	**2020**	**2030**	**2040**	**2020**	**2030**	**2040**
AEO	10,372	10,370	10,375	7	13	13
AEOHEG	10,383	10,381	10,373	7	13	13
AEOHOGR	10,336	10,353	10,347	7	10	12
CPP	10,198	10,215	10,220	68	74	75
CPPEXT	10,221	10,249	10,315	51	55	57
CPPNUC	10,177	10,219	10,222	74	78	80
CPPHEG	10,204	10,255	10,248	68	74	77
CPPHOGR	10,230	10,216	10,225	38	43	43

Source: U.S. Energy Information Administration.

Figure 19. Average heat rate of coal-fired generators in Baseline and Clean Power Plan cases, 2005-40



Source: U.S. Energy Information Administration.

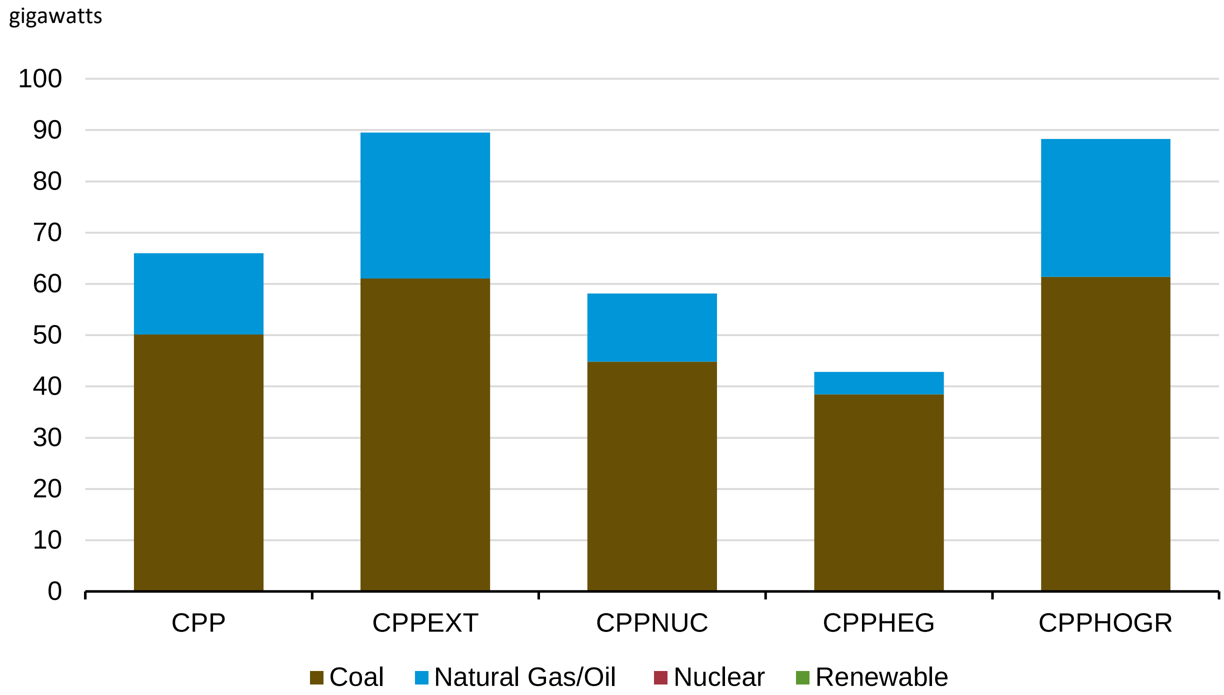
Retirements and capacity additions

Retirements

The emission performance goals in the Clean Power Plan lead to a reduced reliance on existing fossil fuel-fired plants, which results in more retirements. Under the Clean Power Plan, coal-fired capacity accounts for most of the additional retirements relative to the underlying baseline cases (Figure 20). In the AEO2015 Reference case, total retirements of existing capacity are about 90 gigawatts. Coal-fired and natural gas/oil-fired capacity account for 40 gigawatts and 46 gigawatts of the total retirements, respectively. In the Base Policy case, 90 gigawatts of coal-fired capacity and 62 gigawatts of natural gas/oil-fired capacity retires. In the Policy Extension case, additional retirements occur as the emission performance goals continue decreasing after 2030, resulting in total retirements of about 179 gigawatts, including 101 gigawatts of coal-fired capacity and 74 gigawatts of natural gas/oil-fired capacity.

Compared with the AEO2015 Reference case, the AEO2015 High Economic Growth case projects higher demand growth, and the AEO2015 High Oil and Gas Resource case projects lower natural gas prices. The CPPHEG and CPPHOGR cases examine the impacts of the Clean Power Plan under higher demand and lower fuel prices, respectively. With higher electricity demand (CPPHEG), the Clean Power Plan increases total retirements by 43 gigawatts and most of this increment is coal-fired capacity. With lower natural gas prices (CPPHOGR), the emission performance goals in the Clean Power Plan result in 88 gigawatts of additional retirements, about 70% of which is attributed to coal-fired capacity (Figure 20).

Figure 20. Change in generating capacity retirements by fuel type in Clean Power Plan cases relative to baseline (cumulative, 2014-40)

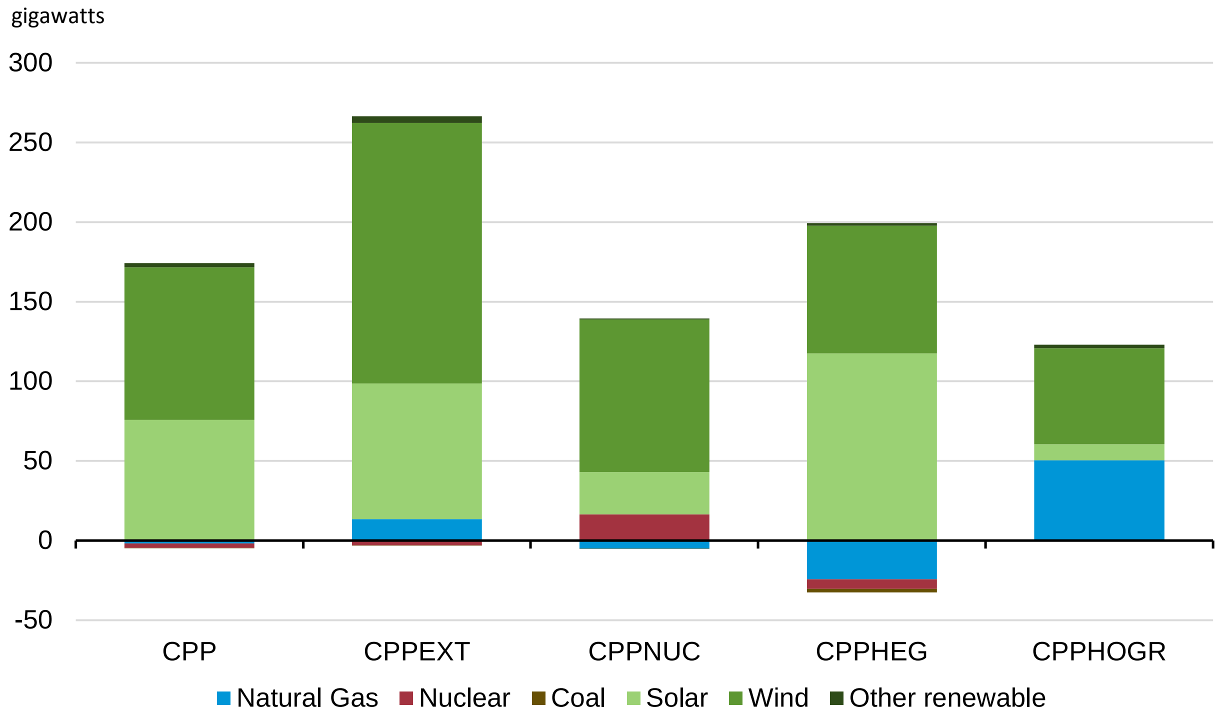


Source: U.S. Energy Information Administration.

Capacity additions

The Clean Power Plan alters the outlook for capacity builds in the electric power sector, substantially increasing builds of renewable electricity capacity in most of the cases analyzed. The increase in renewable capacity builds is largely attributable to the inclusion of new renewable generation in the denominator of EPA's calculation of the achieved intensity standard. In the Base Policy case, cumulative additions of renewable electricity generation capacity through 2040 increase by 174 gigawatts, or 160%, as compared with the underlying AEO2015 Reference case (Figure 21). In the Extended Policies case, renewable electricity generation capacity additions increase by another 79 gigawatts, to 362 gigawatts overall, as regions continue to add zero-carbon resources to meet post-2030 emission performance goals. The largest amount of renewable electricity generation capacity additions occur under AEO2015 High Economic Growth conditions in the CPPHEG case (393 gigawatts). The least amount of renewable electricity generation capacity additions occur in the CPPHOGR case, as low natural gas prices shift the economics of regional compliance strategies away from building new zero-carbon generating capacity, and towards the use of re-dispatch and the construction of new natural gas combined cycle capacity to offset generation from existing sources. Nonetheless, the 138 gigawatts of renewable electricity generation capacity additions in the CPPHOGR case are more than double the level in the underlying AEO2015 High Oil and Gas Resource base case.

Figure 21. Change in cumulative capacity additions, 2014-40, in Clean Power Plan cases relative to baseline

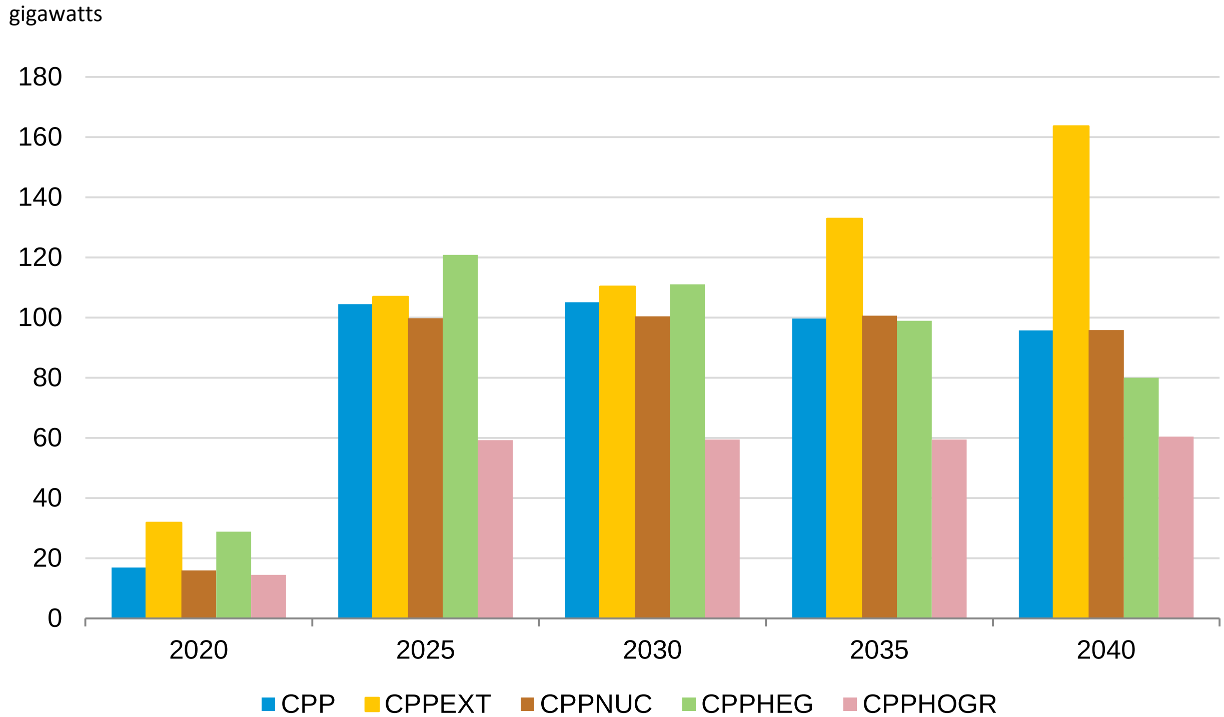


Source: U.S. Energy Information Administration.

Wind power plays an important role in Clean Power Plan compliance, with wind electricity generation capacity more than tripling over 2013 levels by 2040 in the Base Policy case (205 gigawatts in 2040 vs. 61 gigawatts in 2013). Most of the increase in wind electricity generation capacity occurs from 2020-25 (Figure 22), as regions shift their electricity capacity mixes to achieve interim emission performance goals. As a result, in the Base Policy case, installed wind electricity generation capacity in 2025 (188 gigawatts) is more than double the level in the underlying AEO2015 Reference case (84 gigawatts). Wind electricity generation capacity continues to expand moderately after 2030, as regions add zero-carbon capacity to maintain their final emission performance levels.[27] This trend also holds under AEO2015 High Economic Growth assumptions, in the CPPHEG case. In the Policy Extension case, emission performance goals continue to decrease (becoming more stringent) throughout the 2030s, and wind electricity generation capacity continues to play a major role in attaining tightening carbon intensity limits on existing resources. The most substantial amount of post-2030 wind electricity generation capacity expansion occurs in the Policy Extension case, with total installed capacity growing from 198 gigawatts in 2030 to 273 gigawatts in 2040. In the CPPHOGR case, following a period of expansion between 2020 and 2025, wind electricity generation capacity is relatively flat through the late 2020s and 2030s as lower fuel prices lead regions to favor natural gas-fired compliance strategies.

[27] Additionally, wind is increasingly economically competitive with other resource types in the post-2030 timeframe, as can be seen by the late-projection increase in wind electricity generation capacity in the Reference case.

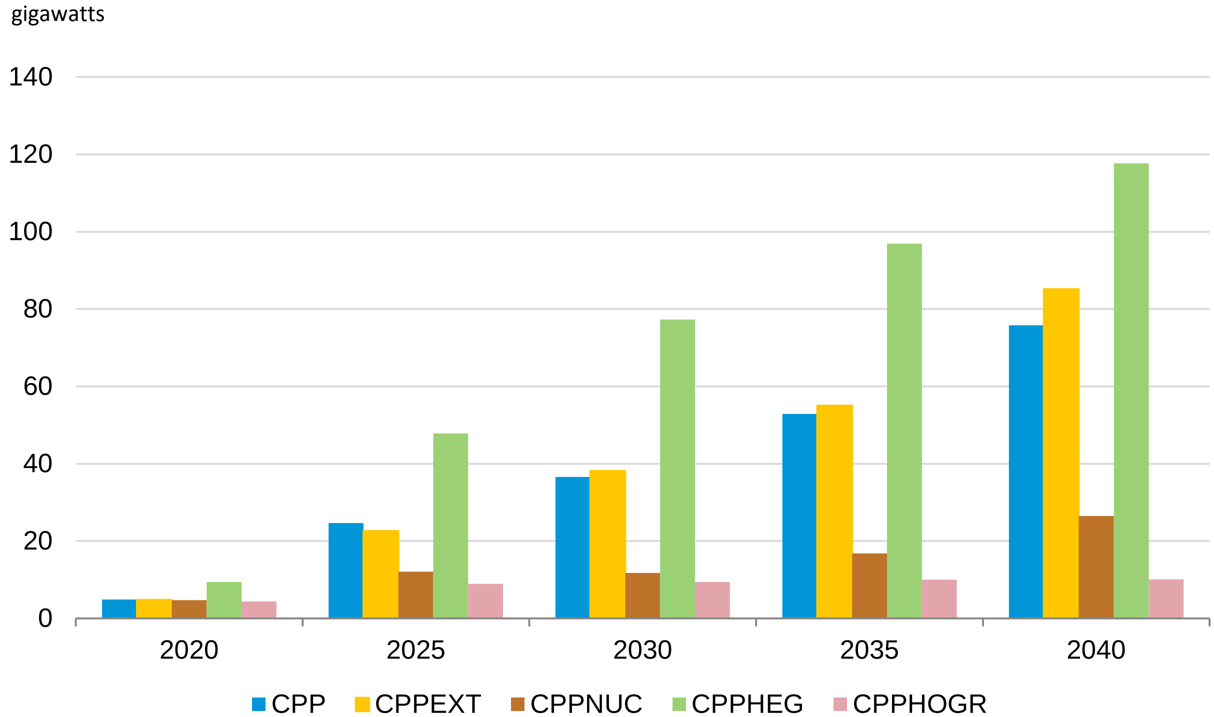
Figure 22. Change in installed wind generating capacity in Clean Power Plan cases relative to baseline



Source: U.S. Energy Information Administration.

The Base Policy case projects 136 gigawatts of installed solar electricity generating capacity in 2040, an increase of 76 gigawatts over the underlying AEO2015 Reference case (Figure 23), as regions with rich solar resources leverage solar technology to reduce carbon intensity and reduce fuel costs. However, solar electricity generation capacity additions vary widely across cases, heavily dependent on the projected paths of electricity use and natural gas prices. The CPPHEG case assumes high economic growth and has the highest total electricity use among the Clean Power Plan cases. The CPPHEG case projects 200 gigawatts of installed solar electricity generation capacity in 2040 (versus 82 gigawatts in the underlying High Economic Growth base case). By contrast, the CPPHOGR case, which assumes AEO2015 High Oil and Gas Resource conditions and low natural gas prices, projects a much smaller increase in solar electricity generation capacity (58 gigawatts in the CPPHOGR case vs. 48 gigawatts in the High Oil and Gas Resource base case). Across the Clean Power Plan cases, all of the solar electricity generation capacity additions above the Reference case level employ solar photovoltaic technology (as opposed to solar thermal technology).

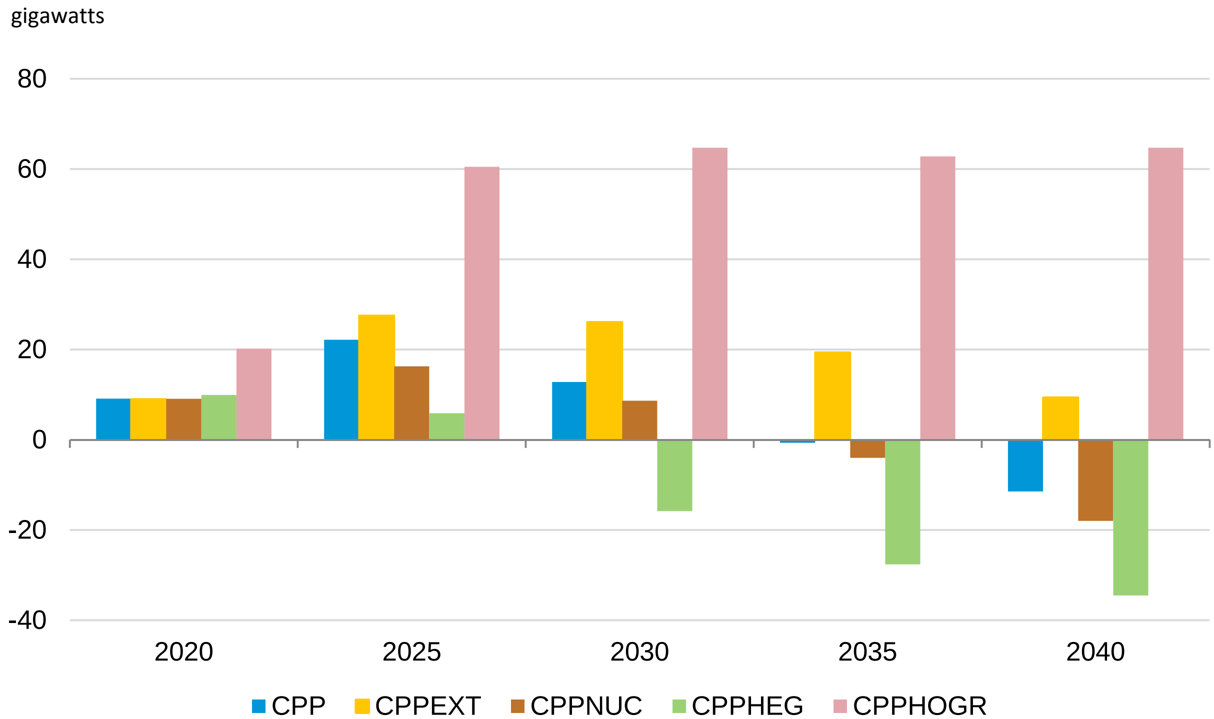
Figure 23. Change in installed solar generating capacity in Clean Power Plan cases relative to baseline



Source: U.S. Energy Information Administration.

Adding new natural gas-fired combined cycle (NGCC) electricity generation capacity can lead to the displacement of generation from affected existing sources in dispatch, which can in turn help a region achieve its Clean Power Plan emission performance goals. However, generation from new natural gas-fired units, unlike new renewable generation, is not included in the base (denominator) generation total used to calculate the emission intensity of existing fossil generation for compliance purposes. Across the cases analyzed, the use of this option depends on the economics of natural gas markets, compliance assumptions, and the relative amount of renewable electricity generation capacity additions. In most cases, the total NGCC electricity generation capacity remains near baseline levels. Under AEO2015 High Oil and Gas Resource assumptions, in the CPPHOGR case, lower natural gas prices lead regions to rely more heavily on natural gas-fired options to reduce the CO_2 emissions from existing sources, as NGCC electricity generation capacity increases from 252 gigawatts in 2020 to 334 gigawatts in 2030, and 386 gigawatts in 2040, 65 gigawatts more than the AEO2015 High Oil and Gas resource case (Figure 24).

Figure 24. Change in installed natural gas-fired combined cycle capacity in Clean Power Plan cases relative to baseline



Source: U.S. Energy Information Administration.

New nuclear

New nuclear capacity represents another zero-carbon technology that could potentially reduce overall CO_2 emissions. The Base Policy with New Nuclear case (CPPNUC) allows credit for generation from unplanned new nuclear plants in compliance calculations. The primary result is that the new nuclear displaces some of the renewable capacity additions as a means of compliance.

Table 7. Nuclear power projections in three cases (gigawatts)

	AEO	CPP	CPPNUC
Nuclear capacity (gigawatts)			
2020	101	101	101
2030	102	101	113
2040	105	102	121
Nuclear Generation Share (percent)			
2020	18	19	19
2030	17	18	20
2040	16	16	19

Source: U.S. Energy Information Administration.

Demand reduction through incremental efficiency programs

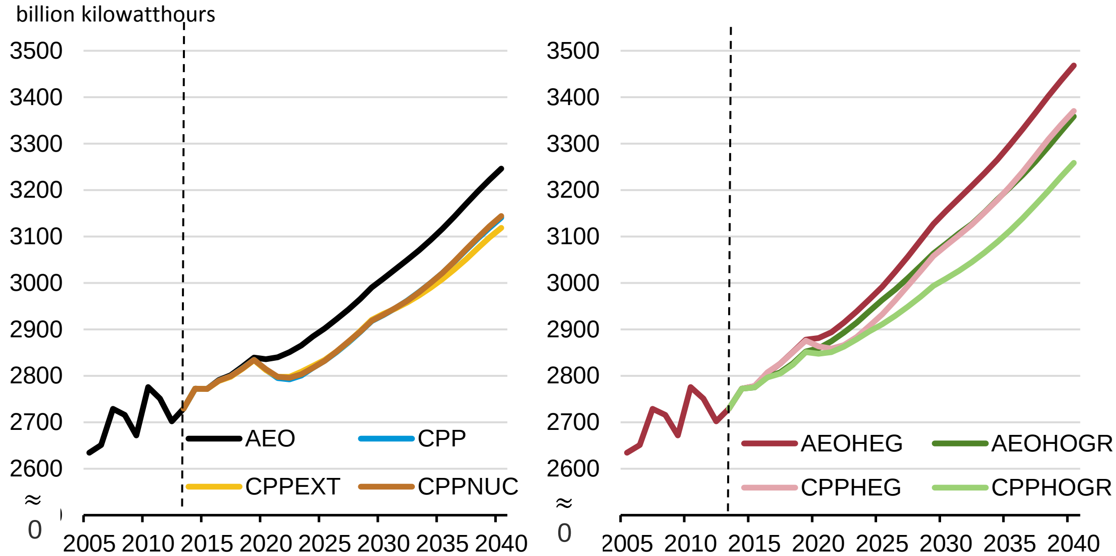
Delivered electricity consumption in the buildings (residential and commercial) sector in 2030 is 2.6% lower in the Base Policy case than in the Reference case (Figure 25). Both energy efficiency (EE) program activity and consumer response to higher electricity prices contribute to the reduction. Buildings sector demand reductions in the four other Clean Power Plan cases are similar, ranging from 2.4% in the CPPHEG case to 2.6% in the Policy with New Nuclear case. When the energy efficiency compliance option is excluded from Clean Power Plan actions, electricity consumption in 2030 in buildings is 0.8% lower than in the Reference case based on electricity price effects alone. If direct rebate levels for the efficiency compliance option increase to 25% of the installed cost of efficient equipment, buildings electricity consumption in 2030 is 4.9% below the Reference case.[28] However, these higher rebate levels are not cost-effective compliance measures under the set of assumptions in this analysis. Renewable energy, natural gas, and other supply-side measures trade off against demand reductions to achieve compliance with the Clean Power Plan's goals; the incremental cost of saved energy is less than the required program investment costs at higher assumed rebate levels. Further discussion of the energy efficiency sensitivity cases is provided in the Additional Sensitivity case section.

The Base Policy case represents a roughly 17% increase in average annual program expenditures from 2012 national energy efficiency program activity over the interim compliance period. In combination with Reference case total demand reductions of about 0.5% per year, it yields just over 0.7% per year in national program-induced savings (if compared with a hypothetical case where no efficiency spending took place). Price-related demand reductions occur in addition to program-induced reductions, resulting in the national change in electric sales from Reference case levels shown in the Clean Power Plan cases.

Using the NEMS end-use modeling approach, EIA's projection of the energy efficiency savings achieved by 2030 for the Base Policy case totals 81 BkWh for use in emission performance calculations. For the four other Clean Power Plan cases, the energy savings range from a high of 80 BkWh in the Policy with New Nuclear case to a low of 75 BkWh in the CPPHEG case.

[28] The methodology underlying modeled efficiency incentives for the Clean Power Plan is described in detail in Appendix F. Table 26 provides assumed rebate levels and timing for efficiency measures by Census division in the Base Policy case.

Figure 25. Delivered buildings electricity consumption, 2005-40



Source: U.S. Energy Information Administration.

Increased utility costs to meet plan requirements are assumed to be passed along to consumers through higher electricity prices. Despite lower residential electricity demand, average annual household electricity bills during the interim compliance period (2020-29) are 3.0% higher in the Base Policy case than in the Reference case. Annual household electricity bills average 2.0% higher during the same period in CPPHEG relative to the AEOHEG case as higher economic growth spreads costs across a larger number of households.

Residential consumers also spend more for energy-using equipment in the Base Policy case relative to the Reference case. By 2030, a net cumulative investment of $2.4 billion in equipment and building shell measures is made by residential consumers after receiving cumulative rebates totaling $6.8 billion. Commercial consumers as a whole invest less in new equipment in the Base Policy case than in the Reference case. By 2030, commercial consumers spend $0.9 billion less cumulatively on new equipment, because $7.4 billion in cumulative rebates are realized by the commercial sector.

Electricity prices

Average retail electricity prices increase, particularly in the near term, as a result of the measures used to comply with the Clean Power Plan. The increased investment in new electricity generation capacity as well as the increased use of natural gas for electricity generation leads to electricity prices in 2020 that are 2% to 5% higher in the compliance cases than the respective base prices (Table 8).[29] The delivered

[29] In competitive pricing, the generation component consists of the marginal energy cost and a capacity payment to represent the marginal cost of meeting reliability requirements (i.e., reserve margins). The marginal energy cost will reflect the Clean Power Plan compliance costs that are related to re-dispatch, but will not account for the incremental investment that is incurred specifically to meet the intensity standard. Therefore, an additional capacity-related payment is calculated for the competitive regions to represent the marginal investment-related costs associated with new plants built to comply with the standards and is added to the retail price.

price of natural gas is also higher as a result of the increased consumption, and is correspondingly passed through to electricity rates. Over the longer term, reliance on natural gas for compliance declines and the fuel price drops back closer to reference case levels, resulting in less of an impact on the electricity price. In 2030, the electricity prices are about 3% to 4% above reference case levels. In 2040, only the Policy Extension case has an average electricity price more than 3% above its baseline price. In general, electricity generation prices in the Clean Power Plan cases remain above their respective baseline case prices in the later years of the forecast because recovery of new generating assets occurs over time, offsetting reductions in fuel expenses. The transmission and distribution prices are also projected to be higher in the compliance cases. The costs of energy-efficiency programs are assumed to be recovered through distribution charges, and transmission costs will increase as the amount of new generating capacity is added and if new interregional transmission capacity is needed.

Table 8. Change in average electricity price components in five cases, relative to baseline levels

	Generation price			Transmission and Distribution price			Total price		
	2020	2030	2040	2020	2030	2040	2020	2030	2040
CPP	5.9%	2.8%	1.2%	3.3%	5.8%	5.0%	4.9%	4.0%	2.6%
CPPEXT	5.8%	2.8%	5.8%	3.5%	6.0%	6.2%	4.9%	4.0%	5.9%
CPPNUC	5.2%	2.7%	0.6%	3.2%	5.6%	4.8%	4.4%	3.8%	2.1%
CPPHEG	3.4%	1.1%	-0.8%	3.5%	5.7%	5.0%	3.4%	2.8%	1.1%
CPPHOGR	1.5%	2.5%	0.0%	2.9%	5.4%	4.9%	2.0%	3.7%	2.1%

Source: U.S. Energy Information Administration.

The electricity price increases are generally lowest in the CPPHOGR case, with less of an impact in 2020 because the AEO2015 High Oil and Gas Resource case is already shifting into natural gas generation, and the increased resource availability results in less of a natural gas price increase under the higher usage case. Although prices increase in the CPPHOGR case relative to the AEO2015 High Oil and Gas Resource case, they are from 3% to 12% below the Reference case prices. In the CPPHEG case, the generation price drops slightly below its baseline by 2040, because the underlying High Economic Growth case already has relatively high prices reflecting increased investment in new capacity to meet the greater demand growth, and fuel costs that rise faster than the Reference case. The addition of the Clean Power Plan under these conditions results in fuel costs that are reduced enough to offset additional capital costs in the later years of the forecast. In the Base Policy case (CPP), electricity prices increase in 2020 relative to the Reference case in all regions, although the level of the impact varies (Table 9). As in the national average, the price impact tends to be the highest in the earlier years, when shifting to natural gas is the main compliance option and natural gas prices rise. To some extent, regions that are able to build renewable capacity more quickly will have less of an early price impact. Additionally, the level of the regional intensity standard is also a factor, as some regions appear to be closer to meeting the standard under the Reference case projections. For example, because California already has a carbon policy and a state renewable portfolio standard, EIA's results show that the Reference case generation mix already comes close to meeting California's Clean Power Plan standard. As a result, the price impact in California is fairly minimal throughout the projection.

Table 9. Change in regional retail electricity prices in two cases, relative to baseline levels[30]

	Base Policy Case			Policy Extension Case		
	2020	2030	2040	2020	2030	2040
U.S. average	4.9%	4.0%	2.6%	4.9%	4.0%	5.9%
Texas	7.3%	0.7%	3.6%	7.2%	0.4%	4.8%
Florida	9.7%	10.9%	6.2%	9.3%	11.6%	8.4%
Eastern Wisconsin	7.0%	6.7%	5.1%	7.5%	7.4%	11.8%
Northern Plains	2.9%	6.3%	2.2%	2.2%	5.8%	3.4%
New England	3.1%	-1.2%	1.0%	3.1%	-2.3%	1.1%
New York City	5.7%	-0.2%	1.8%	6.6%	-2.3%	2.0%
Long Island	2.6%	-1.8%	0.4%	4.4%	-2.0%	0.2%
Upstate New York	5.1%	-0.5%	2.1%	4.9%	0.2%	2.7%
Mid Atlantic	4.4%	0.4%	1.3%	6.8%	-2.8%	3.1%
Lower Michigan	4.0%	6.9%	3.5%	7.7%	4.9%	6.9%
Great Lakes	1.8%	-0.8%	-1.9%	0.8%	-0.4%	5.3%
Mississippi Delta	9.7%	7.0%	7.0%	8.3%	8.8%	8.1%
Mississippi Basin	5.9%	4.6%	0.7%	5.3%	6.0%	9.0%
Southeast	5.2%	10.4%	8.9%	4.8%	10.1%	16.0%
Tennessee Valley	9.4%	8.2%	4.8%	9.6%	11.4%	13.9%
Virginia-Carolina	5.0%	6.8%	4.4%	5.3%	7.7%	7.5%
Central Plains	1.0%	1.7%	-3.1%	0.9%	1.6%	0.3%
Southern Plains	8.4%	10.6%	5.0%	8.6%	10.8%	7.3%
Southwest	7.7%	11.1%	5.4%	6.2%	10.8%	7.8%
California	2.2%	0.6%	0.7%	2.1%	0.6%	1.6%
Northwest	0.8%	2.6%	-1.1%	0.5%	3.1%	1.0%
Rocky Mountain	6.4%	7.0%	0.7%	6.4%	8.2%	7.9%

Source: U.S. Energy Information Administration.

price change from baseline

Decreasing Median (4.9%) Increasing

In most regions the price impact declines by 2040, but several regions in the southeastern United States (Florida, Southeast, Mississippi Delta), as well as the Southwest and Eastern Wisconsin, have prices that are more than 5% above the reference case levels in 2040 in the Base Policy case. Wind resource potential is relatively low in some of these regions, and instead they tend to build relatively more expensive solar photovoltaic capacity to offset their fossil generation and meet emission performance goals. The New England and New York regions tend to have among the lowest price increases by 2040. Several regions (Central Plains, Great Lakes and Northwest) have lower prices by 2040 in the Base Policy case relative to the Reference case. In general, these tend to be regions with favorable wind resources.

Implementation of the Clean Power Plan generally results in higher electricity expenditures, but changes in expenditures are lower in percentage terms than price changes as the combination of energy

[30] Prices used in the creation of this table are all-sectors average (Residential, Commercial, Industrial and Transportation).

efficiency programs pursued for compliance purposes and higher electricity prices tend to reduce electricity consumption relative to baseline levels.

Table 10. Change in electricity expenditures by sector in five cases, relative to baseline levels

	Residential			Commercial			Industrial		
	2020	**2030**	**2040**	**2020**	**2030**	**2040**	**2020**	**2030**	**2040**
CPP	3.4%	1.4%	0.3%	3.9%	1.1%	-1.3%	4.6%	1.6%	0.2%
CPPEXT	3.4%	1.5%	2.3%	4.0%	0.9%	0.7%	4.3%	1.8%	3.7%
CPPNUC	3.1%	1.4%	-0.1%	3.5%	0.9%	-1.7%	4.0%	1.5%	-0.2%
CPPHEG	2.4%	0.8%	-0.6%	2.5%	0.2%	-2.3%	3.1%	1.1%	-1.0%
CPPHOGR	1.4%	1.3%	-0.1%	1.5%	0.9%	-1.7%	2.3%	2.3%	0.6%

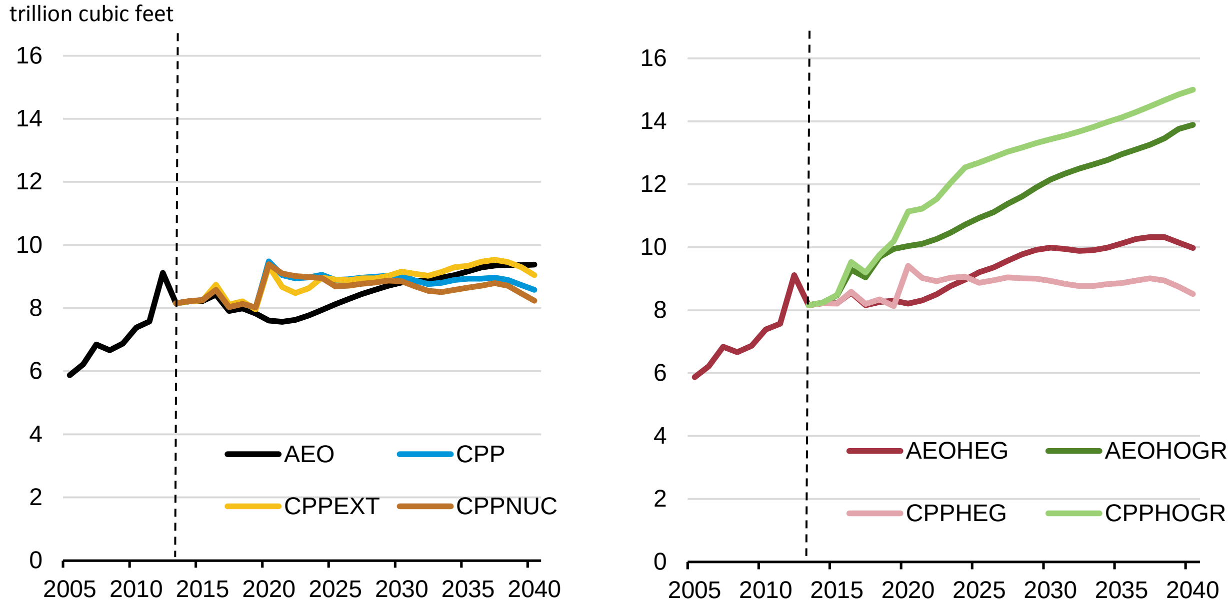
Source: U.S. Energy Information Administration.

Natural gas

Regardless of the underlying case, the Clean Power Plan results in a rapid increase in consumption of natural gas in the electric power sector when implementation begins in 2020. When imposed under AEO2015 Reference and High Economic Growth case assumptions, 2020 is the peak year of projected natural gas consumption for the electric power sector (Figure 26), and the year of the greatest increase over the comparative underlying base case. Following the early 2020s, the increase over the base declines and eventually results in less gas consumption by power generators compared with the underlying baseline case. In the Policy Extension case, increased natural gas consumption by electric power generators over the AEO2015 Reference case continues through 2038.

Under AEO2015 High Economic Growth case assumptions, which project higher natural gas prices than the AEO2015 Reference case, the use of natural gas-fired generation is a less-attractive option to achieve regional emission performance goals under the Clean Power Plan. In the CPPHEG case, there is a smaller increase in power sector gas consumption in 2020, and the move from using more gas to less gas than the underlying case occurs earlier (2025 versus 2032 under Reference case conditions). Relatively low natural gas prices in the CPPHOGR case make natural gas a comparatively economical fuel for electricity generation, driving a continued increase in the difference in natural gas consumption over the underlying AEO2015 High Oil and Gas Resource case beyond 2020 to 2024. As with the other cases, this increase over the base volumes declines thereafter, but stays at a notably higher level.

Figure 26. Electric power sector natural gas consumption in baseline and CPP cases, 2005-40



Source: U.S. Energy Information Administration.

Driven by changes in natural gas consumption in the electric power sector, overall consumption of natural gas follows a similar pattern, and the differences between the Clean Power Plan cases and their respective base cases for electricity and total natural gas consumption are nearly equal. Total natural gas consumption across other sectors only modestly decreases under Reference and High Oil and Gas Resource assumptions under the Clean Power Plan. Total delivered natural gas consumption across other sectors falls less than 2.1% and 1.1%, respectively, in any one year, and less than 1% on average from 2020-40. Under High Economic Growth assumptions, post-2025 natural gas consumption is slightly higher in other sectors, 0.3% on average.

In the early compliance years of the Clean Power Plan, a combination of increased production and lower LNG exports meets the increase in electric power sector natural gas demand. With the exception of the CPPHEG case, dry natural gas production over the 2020 to 2030 period is, on average, 0.9% to 3.6% higher in the Clean Power Plan cases than in the respective base cases. Of this increased production, 55% to 84% comes from increased production from shale plays. In particular, natural gas production is higher in the 2020-21 timeframe (even in the CPPHEG case), when there is also a short-term run-up in natural gas supply prices (Table 11), as the market balances to the higher level of demand. Although there might be a level of market anticipation for increased natural gas demand in 2020, supply pressures drive the increase in prices during the early years. As consumption levels in the Clean Power Plan cases move closer to their base levels, if not below them, relative production levels follow suit, and price differences decline in the second half of the projection period.

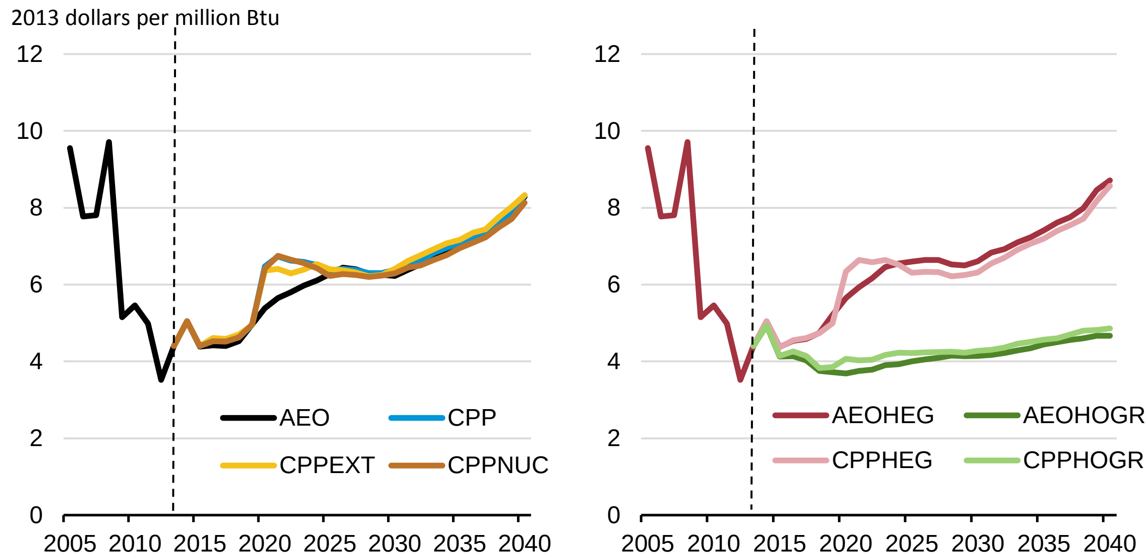
Table 11. Differences in natural gas production from baseline in the CPP cases

	CPP			CPPEXT			CPPNUC			CPPHEG			CPPHOGR		
	2015-2019	2020-2029	2030-2040	2015-2019	2020-2029	2030-2040	2015-2019	2020-2029	2030-2040	2015-2019	2020-2029	2030-2040	2015-2019	2020-2029	2030-2040
United States Total	0%	1%	-2%	0%	0%	-2%	0%	1%	-3%	0%	-1%	-4%	0%	4%	1%
Lower 48 Onshore	0%	1%	-3%	0%	0%	-2%	0%	1%	-3%	0%	-1%	-5%	0%	4%	1%
Tight Gas	0%	0%	-4%	0%	0%	-3%	0%	0%	-4%	0%	-1%	-5%	0%	3%	1%
Shale Gas and Tight Oil Plays	0%	1%	-3%	1%	0%	-3%	0%	1%	-4%	0%	-2%	-6%	0%	5%	2%
Coalbed Methane	0%	1%	1%	1%	0%	1%	0%	1%	1%	0%	1%	1%	1%	1%	1%
Other	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Lower 48 Offshore	0%	1%	1%	0%	1%	1%	0%	1%	0%	0%	1%	-1%	0%	0%	1%
State	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Federal	0%	1%	1%	0%	1%	1%	0%	1%	0%	0%	1%	-1%	0%	0%	1%
Alaska	0%	24%	0%	0%	24%	0%	0%	24%	0%	0%	0%	0%	0%	0%	0%
Onshore	0%	24%	0%	0%	24%	0%	0%	24%	0%	0%	0%	0%	0%	0%	0%
Lower 48 Onshore – by Region															
Northeast	0%	4%	0%	0%	2%	0%	0%	3%	0%	0%	1%	-3%	0%	4%	2%
Gulf Coast	1%	0%	-7%	1%	-1%	-6%	1%	0%	-7%	0%	-4%	-9%	1%	7%	2%
Midcontinent	0%	0%	-3%	0%	-1%	-2%	0%	0%	-3%	0%	-2%	-5%	1%	4%	3%
Southwest	0%	0%	-1%	0%	0%	-1%	0%	0%	-1%	0%	-1%	-2%	0%	1%	1%
Rocky Mountain	0%	0%	-2%	0%	-1%	-2%	0%	0%	-2%	0%	-1%	-2%	0%	2%	0%
West Coast	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

Source: U.S. Energy Information Administration.

The largest changes in natural gas production occur in the Northeast and Gulf Coast regions in the Clean Power Plan cases compared with their respective base cases. In the CPP, CPPEXT, and CPPNUC cases, the increases in production over their respective baselines during the 2020-29 period are driven by increases in the Northeast. In these cases, production from the Marcellus play has the highest percentage increase during that period. During 2030-40, when electric generators consume less natural gas than in their respective base cases, natural gas production similarly decreases; with the relatively low prices in the CPPHOGR case, natural gas consumers consume more than the baseline and natural gas production is higher. The largest declines occur in the Gulf Coast, with natural gas production averaging 6% to 9% less in the Clean Power Plan cases compared with their baselines. In particular, natural gas production from the Eagle Ford shale play falls by 7% to 9% in those cases during that period.

Figure 27. Average delivered natural gas prices to the electric power sector in baseline and Clean Power Plan cases, 2005-40



Source: U.S. Energy Information Administration.

On average from 2015-40, net natural gas exports range from 3% lower (CPPHOGR) to 12% lower (CPPEXT) in the Clean Power Plan cases compared with the underlying base cases. Reduced exports, primarily comprised of domestic LNG, drive the decrease, with the exception of the CPPHOGR case. Net exports have a similar pattern with other segments of the natural gas market in the Clean Power Plan cases, with the greatest impact occurring in the earlier years of the policy's implementation. However, lower LNG export capacity build-out during the early years of the projection period, in anticipation of higher prices, contributes to the overall decrease in LNG exports over the projection period. Under high oil and gas resource assumptions, natural gas prices are relatively low whether or not the Clean Power Plan is implemented, and therefore, LNG exports grow similarly in the CPPHOGR case and its underlying base case through 2034.

Coal

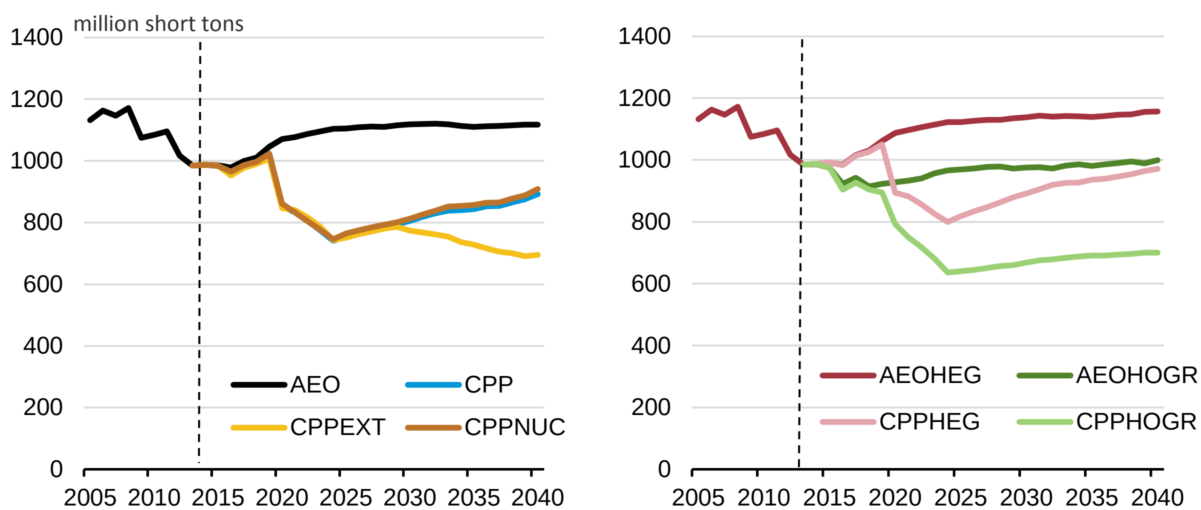
The demand for coal in the power sector declines in every policy case (with respect to its baseline) as a result of Clean Power Plan implementation. Total coal production in the core policy cases is 15% to 21% lower in 2020 compared with baseline projections (Figure 28). In 2040, the comparable decrease in coal production ranges between 16% and 38%. Among the core policy cases, the largest falloff from baseline projections occurs in the Policy Extension case (CPPEXT) where emission performance goals continue to tighten rather than remaining constant after 2030. However, the lowest level of total coal production among the policy cases occurs under the high oil and gas resource availability case (CPPHOGR).

After 2024, coal production in the Base Policy case (CPP) begins to rise from its low of 741 million tons. Coal production increases by 151 million tons after 2024, as an increase in electricity demand growth in combination with expanded use of renewables, rising natural gas prices, and static CPP targets in the post-2030 period allows greater utilization of the existing coal-fired fleet. In 2040, coal production reaches 892 million tons in the Base Policy case. Lower coal demand in three adjacent southeastern Census divisions (South Atlantic, East South Central, and West South Central) contributes to 75% of the decline in 2040 coal production projected in the Base Policy case (CPP). If Clean Power Plan emission performance goals continue to decline post-2030 (Policy Extension case), total coal production also continues to decline, dropping by 48 million tons between 2024 and 2040.

Throughout most of the projection, coal production is lowest under AEO2015 High Oil and Gas Resource assumptions (CPPHOGR), as coal loses more of its share in the electric power sector to natural gas. In 2040, the CPPHOGR case projects a decline in production of 299 million tons relative to the underlying AEO2015 High Oil and Gas Resource case, while in the Base Policy case coal production drops by 225 million tons relative to the AEO2015 Reference case.

High Economic Growth assumptions (CPPHEG case) lead to the highest levels of coal production among the Clean Power Plan cases, and the CPPHEG case also has the steepest slope of recovery for coal in the post-2020 period (0.4% per year). In this case, higher economic growth leads to higher electricity demand. In addition, the CPPHEG case projects the most additions of renewable generating capacity, which allows regions to generate more coal-fired electricity without exceeding the Clean Power Plan's emission performance goals. These factors result in higher utilization of coal plants-and higher coal production-relative to the other cases analyzed.

Figure 28. Total U.S. coal production in baseline and Clean Power Plan cases, 2005-40

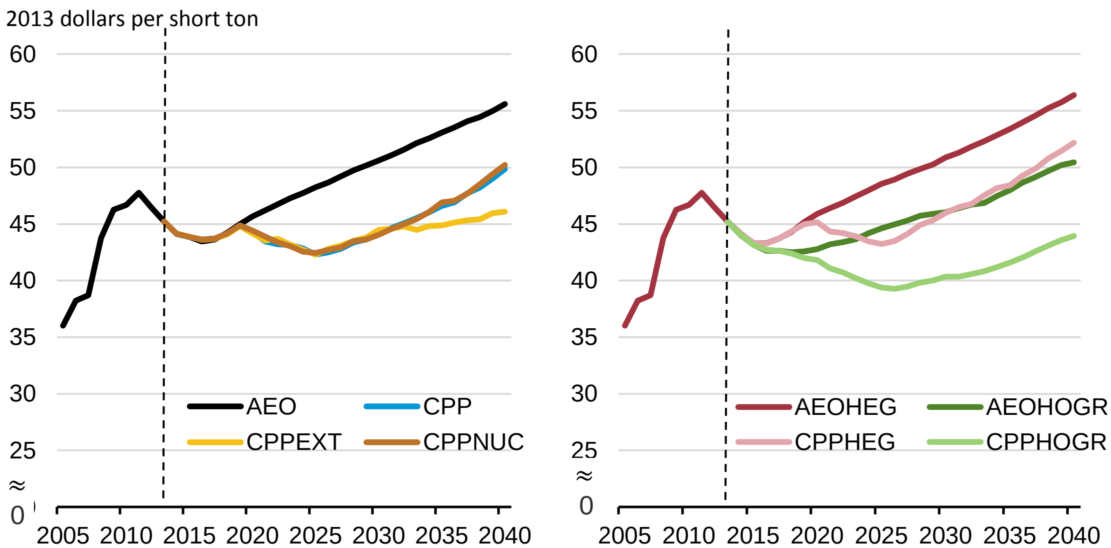


Source: U.S. Energy Information Administration.

Average delivered coal prices to the power sector are lower than the baseline cases in all of the Clean Power Plan cases analyzed (Figure 29). In the Base Policy case (CPP), delivered coal prices fall to 13% below the underlying AEO2015 Reference case baseline levels in 2030, and rebound slightly to 10% below base in 2040. In the Policy Extension case, where emission performance goals continue to decline after 2030, delivered coal prices see the largest percentage drop, falling to 17% below Reference case levels in 2040. Demand for coal under the Clean Power Plan is strongest with AEO2015 High Economic

Growth assumptions (CPPHEG), where delivered coal prices are 10% below the underlying base case in 2030 and 7% below the base case in 2040. In the CPPHOGR case, delivered coal prices are 12% to 14% below baseline levels between 2030 and 2040.

Figure 29. Average delivered coal prices to the electric power sector in baseline and Clean Power Plan cases, 2005-40

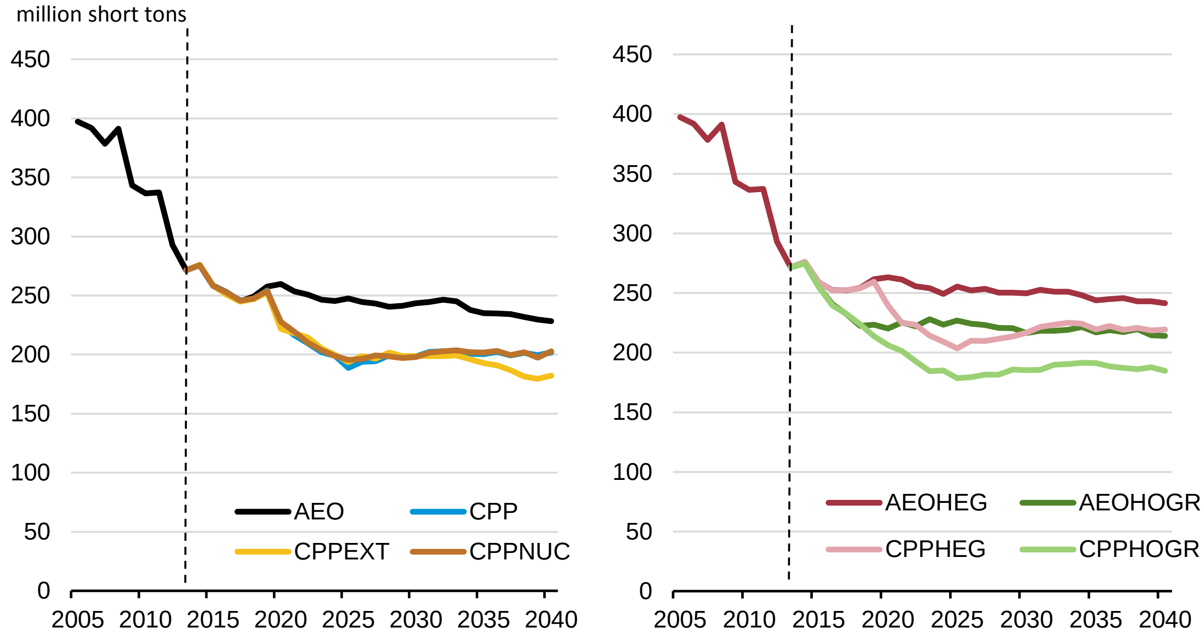


Source: U.S. Energy Information Administration.

Regional coal production

In the Base Policy case, production of higher-cost Appalachian coal declines sharply after 2019, relative to the underlying AEO2015 Reference base case (Figure 30). Appalachian coal production is then relatively flat throughout the remainder of the Base Policy case projection but continues to decline when post-2030 emission performance goals are assumed in the Policy Extension case.

Figure 30. Appalachian coal production in baseline and Clean Power Plan cases, 2005-40



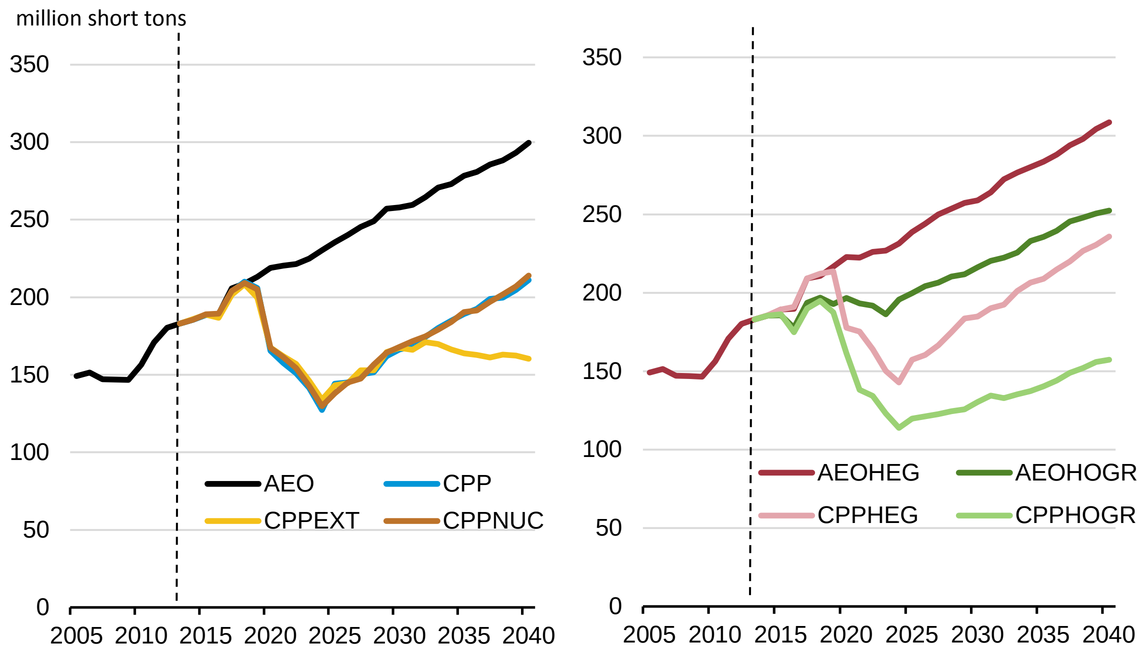
Source: U.S. Energy Information Administration.

When the Clean Power Plan first takes effect, Interior and Western region coal production decline by similar percentages compared with their AEO2015 Reference case levels, 24% and 22% in 2020, respectively (Figure 31 and Figure 32). However, for the Western region this decline represents a drop of 130 million tons, more than twice the decline for the Interior region (53 million tons). While higher-cost Appalachian coal never shows signs of recovery in the Base Policy case, production of less-costly Interior and Western coal does rebound somewhat, though total coal production never attains 2013 levels within the projection period. After 2024, Interior and Western production increase by 84 and 65 million tons, respectively. In the Policy Extension case in the post-2030 period, Western coal production continues to decline relative to the Base Policy case, but Interior coal production first rises slightly from 2025 to 2030 before ultimately flattening out.

Across the policy cases, Interior coal production consistently shows some recovery over the projection after sustaining an initial decline in production. Relatively higher productivity expectations for the Illinois Basin (part of the Interior region) contribute to lower mine production costs for the region. Additionally, regions which increase their demand for coal in the later years of the projection also tend to be regions where Interior coal is projected to be economically competitive. These regions include the South Atlantic Census division for the Eastern Interior coal and the West South Central Census division for Gulf Lignite.

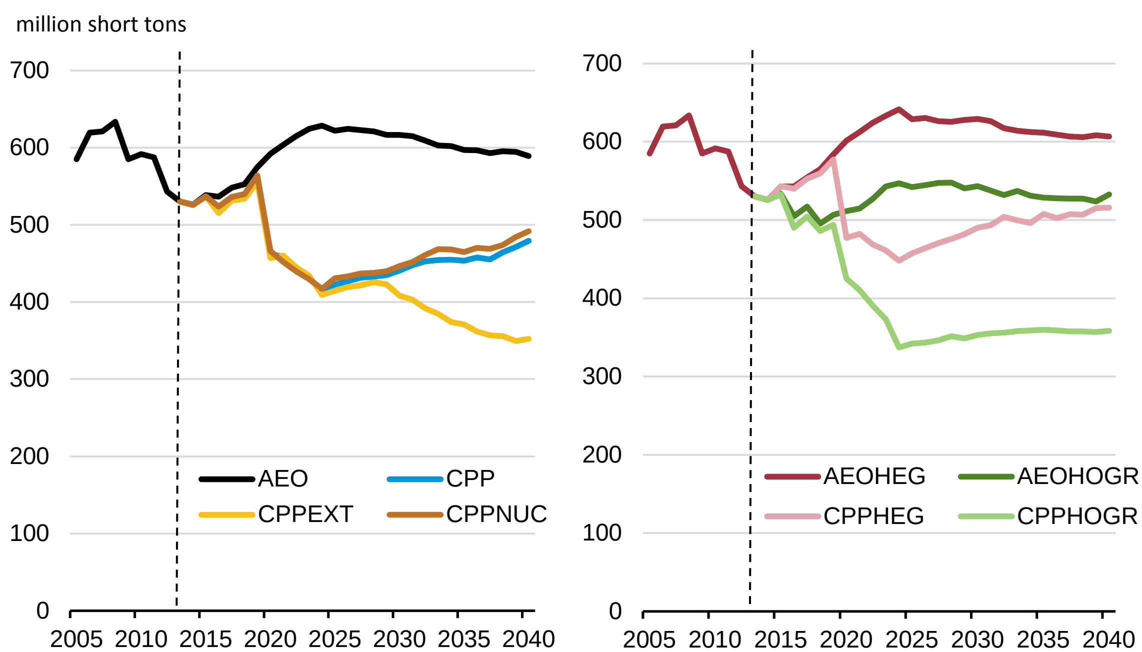
In the High Oil and Gas Resource Policy case (CPPHOGR), Western coal production initially falls and then gradually increases by 21 million tons in 2040 compared to 2024 levels, a smaller increase than the Interior region's rebound of 43 million tons over the same time period. The Western region is less resilient than the Interior region in this case partly because many of the demand regions for Western coal are also regions where natural gas tends to be more competitive with coal.

Figure 31. Interior coal production in baseline and Clean Power Plan cases, 2005-40



Source: U.S. Energy Information Administration.

Figure 32. Western coal production in baseline and Clean Power Plan cases, 2005-40



Source: U.S. Energy Information Administration.

Further regional impacts

As previously indicated, two key attributes of the Clean Power Plan are 1) the establishment of state-by-state emissions intensity targets and 2) the provision of flexibility in choosing how to comply, accounting for differences in the regions.

Regional differences in renewable penetration

The projected changes in electricity generation from renewables have significant implications for regional power systems supporting these areas. Table 12 compares the changing pattern of percentage growth in renewables generation for all EMM regions between the Reference (AEO) and Base Policy (CPP) cases over three phases of implementation: pre-compliance (2015-19), interim compliance (2020-29), and post-compliance (2030-40). From an overall perspective, on average the proposed rule extends a period of strong growth for renewable generation, so that instead of declining from 3.5% to 0.9% growth per year in the Reference case from the pre-compliance period to the interim compliance period, the growth in renewable generation in the Base Policy case increases to 5.0% per year. Over the long term, the rate of renewables growth approaches a steady annual rate in the range of 1.7%-1.9% in both cases.

Table 12. Growth rates for renewable generation by EMM region and compliance period for two cases, sorted by 2020-29 CPP growth rate

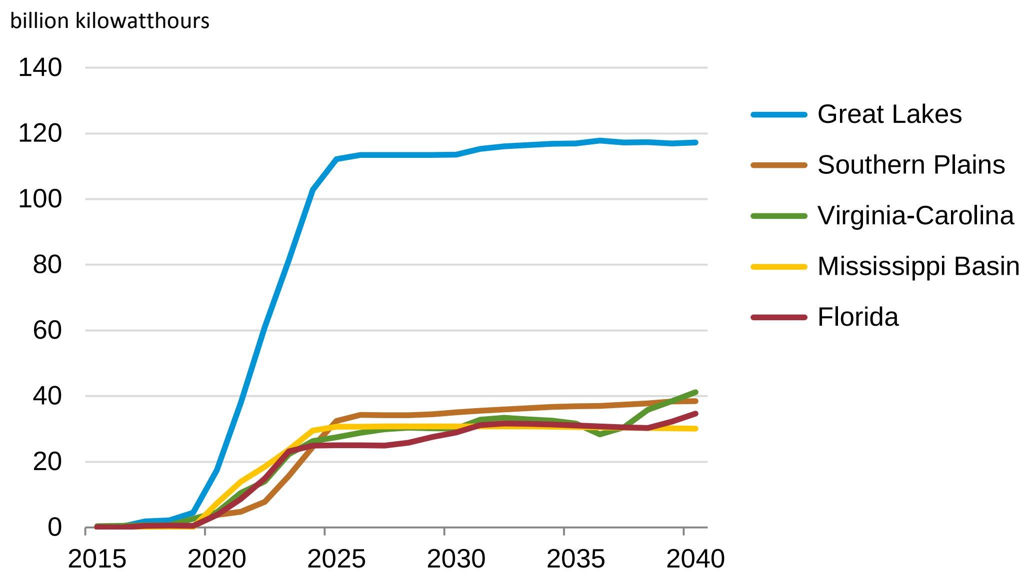
Region	2015-2019		2020-2029		2030-2040	
	AEO	CPP	AEO	CPP	AEO	CPP
Florida	2.0%	2.0%	1.8%	15.0%	4.9%	3.4%
Great Lakes	4.9%	6.6%	0.4%	13.7%	1.3%	0.5%
Virginia-Carolina	5.0%	7.1%	2.0%	10.6%	4.8%	3.5%
Mississippi Basin	7.8%	8.0%	0.6%	10.3%	1.7%	0.2%
Mid-Atlantic	2.4%	2.0%	2.0%	8.2%	2.0%	2.9%
Rocky Mountain	1.1%	1.1%	1.5%	7.1%	3.7%	1.3%
Lower Michigan	4.3%	13.1%	1.6%	6.9%	1.2%	1.4%
Southern Plains	7.3%	7.5%	0.2%	6.0%	0.6%	0.7%
Southwest	5.8%	5.8%	0.5%	5.5%	3.5%	4.3%
Tennessee Valley	2.2%	3.3%	0.7%	5.0%	1.2%	1.3%
U.S. Total	**3.5%**	**3.9%**	**0.9%**	**5.0%**	**1.9%**	**1.7%**
Northern Plains	2.8%	3.0%	0.2%	4.0%	1.9%	0.6%
Central Plains	3.5%	3.5%	0.4%	3.8%	8.2%	0.5%
Southeast	0.7%	2.0%	0.2%	3.5%	0.7%	6.7%
Mississippi Delta	1.0%	1.6%	0.9%	2.9%	2.6%	2.3%
Texas	3.5%	4.0%	0.5%	2.4%	1.7%	4.6%
Eastern Wisconsin	1.7%	2.5%	1.3%	2.3%	2.2%	2.7%
California	4.6%	4.5%	2.3%	2.1%	1.9%	2.0%
Northwest	2.2%	2.1%	0.5%	1.8%	1.2%	0.3%
Long Island	2.2%	3.6%	2.0%	1.6%	1.8%	1.8%
New England	6.8%	7.6%	1.0%	1.5%	0.5%	0.4%
New York City	1.1%	1.1%	1.3%	1.4%	1.8%	1.9%
Upstate New York	2.2%	2.2%	0.1%	1.3%	0.1%	0.1%

Source: U.S. Energy Information Administration.

At a regional level there is significant variability in the expected impact on renewable sources. The strongest growth in generation is projected for regions which either do not have renewable portfolio standards (RPS) in place (Florida and the Mississippi Basin), or have only modest requirements (i.e., the Virginia-Carolina region). Conversely, the areas with the slowest expected growth in renewable generation are among those which have set higher RPS requirements (New York, New England, and the Pacific Northwest).

The projected pattern of renewable generation growth among the fastest-growing regions is similar. As shown in Figure 33, all of the regions shown experience consistent growth in renewable generation in the Base Policy case relative to the AEO2015 Reference case at the beginning of the interim compliance period from 2020-29 before leveling off for the remainder of the period. In absolute terms, the growth is most pronounced for the large Great Lakes region. Three of the remaining regions (Southern Plains, Florida, and the Virginia-Carolina region) similarly add about 35-40 BkWh over the interim compliance period.

Figure 33. Difference in renewable generation (Base Policy case vs. AEO2015 Reference case) in top five growth regions, 2015-40



Source: U.S. Energy Information Administration.

Regional differences in natural gas-fired generation

Under the Base Policy case (CPP) conditions, the expected change in natural gas-fired capacity is greatest at the outset of the program. The projected increase in natural gas generation in 2020 is 265 BkWh. However, the use of natural gas capacity declines steadily thereafter, and by 2029 the projected increase in natural gas generation in the Base Policy case relative to the AEO2015 Reference case is 74 BkWh. From a national perspective, the projected tapering off of natural gas generation under the Base Policy case translates into little to no growth in natural gas generation over the entire interim compliance period, in contrast with a moderate 2.1% annual average increase under the Reference case (Table 13).

Table 13. Growth rates for natural gas generation by EMM region and compliance period for two cases, sorted by 2020-29 CPP growth rate

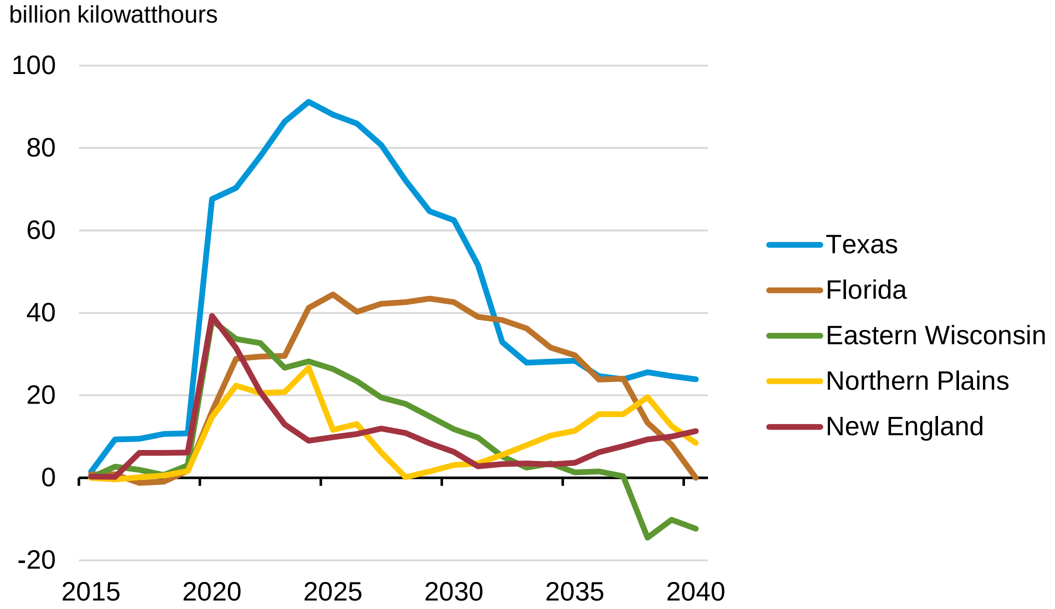
Region	2015-2019		2020-2029		2030-2040	
	AEO	CPP	AEO	CPP	AEO	CPP
Mid Atlantic	-0.5%	-1.2%	1.7%	4.0%	2.9%	0.4%
Long Island	-12.1%	-10.1%	2.7%	3.5%	3.2%	0.4%
Mississippi Delta	-3.7%	-3.2%	5.1%	3.4%	0.9%	1.3%
Southeast	0.3%	0.4%	-0.2%	2.1%	1.7%	-1.1%
Upstate New York	-7.0%	-7.9%	-0.8%	2.0%	3.3%	1.0%
California	0.0%	-0.2%	2.3%	2.0%	1.1%	0.4%
Mississippi Basin	11.9%	12.1%	11.1%	1.7%	6.6%	6.1%
Texas	0.6%	2.0%	2.2%	1.7%	1.5%	-0.5%
Central Plains	-0.9%	-0.6%	2.1%	0.7%	3.3%	1.7%
U.S. Total	**-0.1%**	**0.4%**	**2.1%**	**0.4%**	**1.4%**	**0.0%**
New England	-0.8%	-1.1%	0.6%	0.0%	0.9%	0.7%
Great Lakes	-4.3%	-4.8%	4.1%	-0.2%	2.6%	2.2%
Florida	1.5%	2.9%	2.2%	-0.5%	-0.2%	-0.9%
Lower Michigan	14.0%	13.5%	-0.1%	-0.7%	0.8%	-1.1%
Northwest	-11.6%	-11.9%	7.4%	-1.5%	-0.2%	-1.2%
Tennessee Valley	15.9%	21.2%	4.0%	-1.6%	-0.4%	1.3%
Virginia Carolina	11.3%	12.9%	0.5%	-3.6%	1.2%	-2.4%
New York City	-9.4%	-9.1%	-0.9%	-4.1%	2.2%	0.8%
Southwest	-1.4%	-0.5%	0.0%	-4.5%	-0.8%	-0.8%
Southern Plains	3.3%	3.7%	2.3%	-4.9%	1.8%	0.0%
Rocky Mountain	-7.7%	-9.0%	8.3%	-4.9%	3.3%	1.2%
Northern Plains	12.9%	14.5%	5.7%	-6.9%	2.9%	3.5%
Eastern Wisconsin	1.7%	3.7%	6.6%	-7.9%	1.8%	3.6%

Source: U.S. Energy Information Administration.

The regional impact of the proposed rule on combined cycle utilization appears to be the inverse of renewables growth, with some of the strongest regions for renewables (Florida, Great Lakes, and Virginia-Carolina regions) being among the slow-growing or declining regions for natural gas-fired generation. On the other hand, some of the lagging regions in renewables (Texas and Mississippi Delta) are among the faster-growing regions in the natural gas-fired generation group.

Figure 34 indicates the difference in natural gas-fired generation between the Base Policy case and the Reference case for the top five EMM regions for natural gas generation growth under the Clean Power Plan. Among these regions, Texas shows the largest initial absolute increase in natural gas generation under the Clean Power Plan, over Reference case levels, before declining again by 2030. The remaining four growth regions (Florida, Eastern Wisconsin, the Northern Plains and New England) exhibit smaller initial boosts in gas generation, before eventually converging to nearly no change from baseline levels.

Figure 34. Difference in natural gas-fired generation (Base Policy case vs. AEO2015 Reference case) in top five growth regions, 2015-40



Source: U.S. Energy Information Administration.

Regional differences in the operation of coal-fired generating units

Coal-fired power plants are expected to reduce output over the compliance period under the Clean Power Plan. For the United States as a whole, under the Base Policy Case (CPP) in the interim compliance period through 2029, the proposed rule results in an annual decrease of 1.8% in coal-fired generation (Table 14). However, over the 2030-40 period coal generation under the Base Policy Case is expected to recover modestly to a 1.1% annual growth rate.

Table 14. Growth rates for coal-fired generation by EMM region and compliance period for two cases, sorted by 2020-29 CPP growth rate

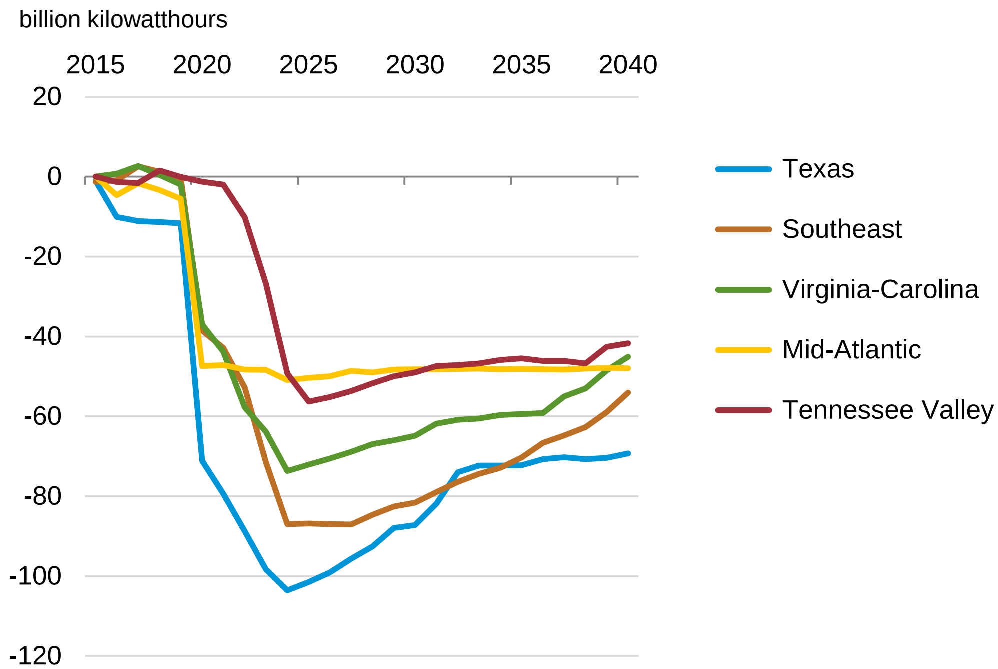
Region	2015-2019		2020-2029		2030-2040	
	AEO	CPP	AEO	CPP	AEO	CPP
Tennessee Valley	-1.5%	-2.5%	0.1%	0.1%	0.0%	0.0%
New York City	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Long Island	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Rocky Mountain	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Great Lakes	1.8%	1.6%	0.2%	-0.2%	-0.1%	0.3%
Northern Plains	2.5%	1.8%	0.1%	-0.4%	0.0%	0.3%
Central Plains	1.1%	0.9%	0.0%	-0.5%	-0.1%	0.4%
Southern Plains	-2.6%	-2.9%	0.1%	-0.5%	-0.1%	1.9%
Southwest	-0.9%	-0.9%	-0.2%	-0.6%	-0.1%	5.4%
Northwest	8.0%	7.9%	-0.8%	-0.8%	-0.1%	-0.2%
Mississippi Basin	1.2%	0.4%	0.2%	-1.1%	-0.1%	0.1%
U.S. Total	**1.2%**	**0.7%**	**0.0%**	**-1.8%**	**-0.1%**	**1.1%**
Lower Michigan	-5.9%	-6.7%	0.4%	-2.4%	-0.1%	1.0%
Virginia-Carolina	2.1%	1.7%	0.3%	-3.0%	-0.1%	2.1%
Texas	1.3%	-0.8%	0.0%	-3.7%	0.0%	3.6%
Florida	-1.1%	-4.9%	0.3%	-6.0%	0.0%	6.9%
Southeast	3.8%	4.0%	0.3%	-7.1%	-0.2%	4.6%
Mississippi Delta	1.8%	1.8%	0.0%	-7.5%	-0.1%	2.1%
Eastern Wisconsin	-5.8%	-6.1%	0.2%	-7.9%	0.0%	4.3%
Mid-Atlantic	1.3%	1.3%	0.2%	-9.2%	0.2%	2.4%
New England	18.3%	55.9%	-0.1%	-11.7%	-0.2%	10.2%
Upstate New York	61.5%	58.8%	2.2%	-16.3%	0.1%	1.1%
California	0.3%	0.3%	-23.0%	-20.0%	0.2%	-0.6%

Source: U.S. Energy Information Administration.

In absolute terms, the changes in coal output reflect a combination of the expected results for natural gas and renewable generation. As a general rule, the regions in the Base Policy case which have above-average growth in renewable generation and/or natural gas-fired generation growth are projected to exhibit declining coal generation (Texas and the Virginia-Carolina region, see Figure 35).

For those EMM regions projected to undergo the strongest declines in coal generation, the pattern of change is a mirror image to the front-loaded natural gas-fired and renewables generation capacity additions. For three of the regions, (Southeast, Mid-Atlantic and Eastern Wisconsin) the largest declines in coal-fired generation occur at the outset of the interim control period in 2020, and then either flatten out or recover.

Figure 35. Difference in coal-fired generation (Base Policy case vs. AEO2015 Reference case) in top five regions of decline, 2015-40



Source: U.S. Energy Information Administration.

Regional differences in demand reduction

States exhibit clear regional differences in levels of demand-side energy efficiency (EE) savings they will achieve by 2030 under the Base Policy case (CPP) relative to the Reference case (AEO). The U.S. averages a 2.5% reduction in electricity sales from efficiency programs and rebates by 2030 in the Base Policy case, relative to the AEO2015 Reference case. Reductions in demand attributed to energy efficiency range from 3.7% in the Rocky Mountain and Southwest regions (EMM regions RMPA and AZNM) to 0.77% in New England (NEWE).

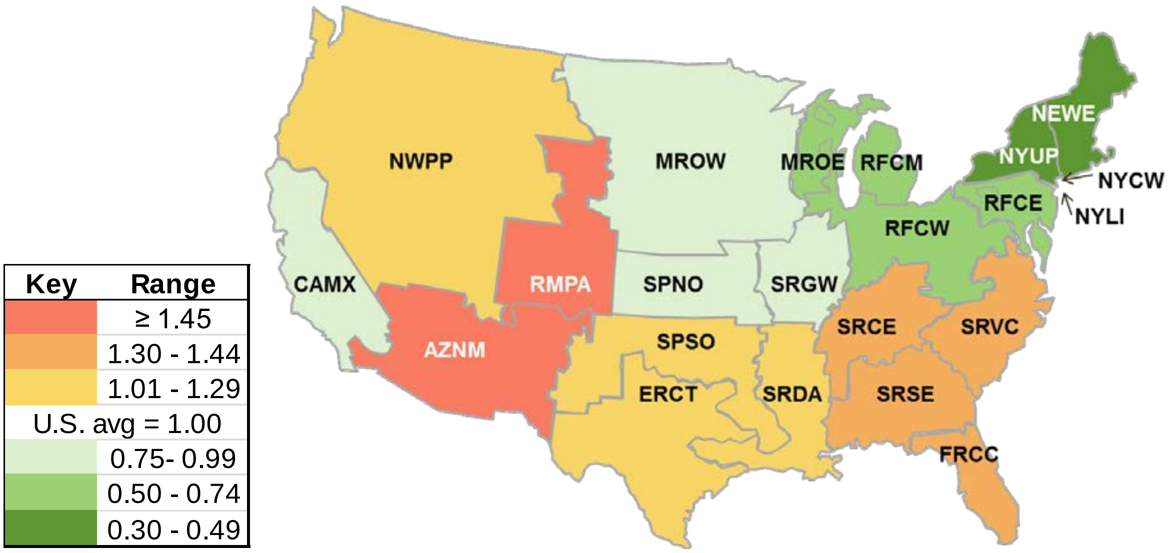
Figure 36 illustrates demand reductions in the 22 EMM regions modeled by NEMS. The map represents demand reductions as a ratio of regional efficiency gains under the Base Policy case (CPP) to average national reductions (where the U.S. is 1.0) relative to total 2030 sales in the Reference case (AEO). Ten regions shaded in red, yellow, and orange produce efficiency savings during the interim compliance period (2020-29) at a higher rate than average; the twelve green-shaded regions produce lower-than-average reductions.

Similarly to aggregate state-level growth rates in renewable resources, many states with a history of strong energy efficiency policy encouragement exhibit lower demand reductions under the Base Policy case (CPP). By early 2015, nearly 30 states had adopted state-level efficiency policies, including energy efficiency resource standards (EERS), EE pilots, or EE goals[31]. These policies were first established in

[31] Analysis by U.S. Energy Information Administration using data in: American Council for an Energy Efficient Economy (ACEEE), *State Energy Efficiency Resources Standards (EERS)* (April 2015), accessed May 15, 2015; ACEEE, *State and Local Policy*

1997, although most were enacted between 2007 and 2009. Long-standing state-level efficiency targets may result in fewer low-cost efficiency gains available during the interim Clean Power Plan compliance period. While NEMS includes state-level renewable (e.g. RPS) policies, it does not explicitly include state-level EE policies. Regional incremental EE activities are implicitly captured in this analysis, however, through the implementation of Census division-level rebates. Appendix F and Table 26 provides details on assumed rebate levels, covered programs, and implementation timing.

Figure 36. Regional EMM demand-side reductions, Base Policy relative to AEO Reference, 2030 sales



Note: ratios are regional changes relative to average U.S. change
Source: U.S. Energy Information Administration.

Table 15. Cumulative demand-side efficiency reductions to 2030 by EMM region, sorted by ratio to U.S. average

Region	Ratios
RMPA - Rocky Mountain	1.51
AZNM - Southwest	1.49
FRCC - Florida	1.36
SRVC - Virginia-Carolina	1.36
SRSE - Southeast	1.34
SRCE - Tennessee Valley	1.31
NWPP - Northwest	1.16
SRDA - Mississippi Delta	1.13
SPSO - Southern Plains	1.09
ERCT - Texas	1.06
U.S. Lower 48 states	**1**

Database, accessed May 15, 2015; *Database of State Incentives for Renewables and Efficiency* (DSIRE); and state public utility commission (PUC) websites.

Table 15. Cumulative demand-side efficiency reductions to 2030 by EMM region, sorted by ratio to U.S. average, continued

Region	Ratios
SPNO - Central Plains	0.91
CAMX - California	0.83
MROW – Northern Plains	0.81
SRGW - Mississippi Basin	0.77
RFCE - Mid-Atlantic	0.73
RFCW - Great Lakes	0.68
RFCM - Lower Michigan	0.6
MROE - Eastern Wisconsin	0.58
NYLI - Long Island	0.43
NYUP - Upstate New York	0.4
NYCW - New York City	0.37
NEWE - New England	0.31

Source: U.S. Energy Information Administration.

Reliability and infrastructure impacts

Reliability of the electric power system can be broadly divided into the categories of adequacy and security.[32] Adequacy includes ensuring sufficient generating capacity to meet peak demand with a very high probability, as specified by reliability standards. Security includes the ability of the system to survive sudden disruptions.

As the NEMS Electricity Market Module (EMM) is not a suitable model for conducting reliability analyses, this report does not provide a reliability assessment of the Clean Power Plan. The analysis does, however, attempt to represent adequacy requirements by ensuring that each EMM region carries adequate resources to meet projected peak demands, plus an assumed reserve margin. Intermittent generation capacity is significantly discounted relative to dispatchable capacity in adequacy calculations based on the availability characteristics of each renewable resource within each of the model's regions during peak load conditions. However, as discussed below, the adequacy analysis in the EMM does not consider possible limitations on fuel availability for generation capacity fueled by natural gas during cold winter weather, when high demand for natural gas for heating homes and commercial buildings may coincide with high electricity demand.

This analysis projects that the Clean Power Plan would result in substantial expansion of renewable generating capacity, and substantial retirements of fossil fuel-fired generation. To accommodate the projected penetrations of intermittent renewable resources, coupled with projected retirements of base load capacity, system requirements would need to be examined with respect to planning and operational contexts.

[32] North American Electric Reliability Corporation (NERC), Frequently Asked Questions, August 2013, accessed February 1, 2015.

High penetrations of intermittent renewable capacity could lead to changes in capacity or ancillary services requirements in order to ensure sufficient system flexibility. An additional caveat to this analysis is that it may not capture future system requirements that could change the projected capacity mix under the proposed rule.

Compliance with the proposed rule could necessitate significant investment in electric transmission system infrastructure to integrate renewables from remote areas. NEMS represents power transfers between regions, but it does not represent constraints on power transfers within EMM regions. While NEMS builds interregional transfer capacity when economic, it does not include a detailed model of the bulk transmission system and does not assess the reliability of these interactions in detail. In addition, the activity surrounding the funding, siting, and construction of transmission infrastructure involves numerous complexities that are beyond the scope of the NEMS model and this study.

Fuel diversity and availability of fuel supplies are another aspect of reliable power system operations. Under the Clean Power Plan, some regions will shift their fuel mix away from baseload capacity with on-site fuel supplies (such as coal, nuclear, hydroelectricity, and oil) towards capacity that tends to utilize real-time fuel delivery (natural gas-fired, as well as intermittent energy resources). Table 16 below reports regional generation shares based on 3 categories: dispatchable generation with on-site fuel (coal, nuclear, hydroelectricity, oil, biomass, and geothermal), dispatchable generation with real-time fuel (natural gas) and intermittent generation (wind and solar). As shown in the table, implementation of the Clean Power Plan shifts generation shares away from dispatchable capacity with on-site fuel towards the other two categories. In some areas subject to cold winter weather, such as Eastern Wisconsin, the Northern Plains, the Central Plains, Lower Michigan, and Upstate New York, the Clean Power Plan is projected to significantly reduce the share of dispatchable generation with on-site fuel supply.

There are several ways to mitigate potential issues that may arise from increased reliance on generation using real-time fuels and intermittent renewable generation. For example, regulators may encourage natural gas-fired generators to secure firm pipeline capacity to reduce or eliminate situations in which insufficient natural gas is available to meet both heating and generation requirements on the coldest days. Another strategy focuses on maintaining the capability to generate with on-site fuels. One possible option is to maintain back-up distillate fuel supplies for natural gas-fired plants that have the capability of burning either fuel. Another option would be to maintain back-up coal-fired capacity that could be dispatched as an alternative to natural gas-fired generation when natural gas supply is constrained. The various options are not mutually exclusive, nor are they costless. To the extent that it is necessary for states to pursue some combination of these options to assure reliability, the cost of doing so, which is not reflected in the electricity price analysis in this report, would likely be borne by electricity consumers.

Table 16. Regional generation shares by fuel category, baseline and Clean Power Plan cases

	Onsite fuel			Real-time fuel			Intermittent		
Region - Case	**2013**	**2020**	**2030**	**2013**	**2020**	**2030**	**2013**	**2020**	**2030**
Texas - Reference	45%	47%	42%	46%	43%	48%	9%	11%	10%
- CPP		29%	22%		61%	64%		11%	14%
- CPPEXT		29%	21%		61%	65%		11%	13%
- CPPNUC		28%	21%		61%	67%		11%	12%
Florida - Reference	37%	41%	37%	63%	58%	62%	0%	0%	1%
- CPP		24%	21%		75%	67%		1%	12%
- CPPEXT		24%	21%		74%	68%		1%	10%
- CPPNUC		23%	44%		75%	54%		2%	2%
Eastern Wisconsin - Reference	89%	90%	85%	8%	6%	10%	3%	4%	5%
- CPP		64%	59%		22%	15%		14%	26%
- CPPEXT		67%	54%		15%	15%		18%	30%
- CPPNUC		66%	58%		20%	13%		15%	29%
Northern Plains - Reference	78%	77%	75%	5%	4%	6%	17%	19%	19%
- CPP		71%	66%		9%	5%		20%	30%
- CPPEXT		71%	65%		9%	5%		20%	30%
- CPPNUC		72%	66%		8%	4%		20%	30%
New England - Reference	53%	39%	38%	45%	54%	55%	2%	6%	7%
- CPP		39%	38%		55%	54%		7%	8%
- CPPEXT		39%	36%		55%	54%		7%	10%
- CPPNUC		39%	37%		54%	55%		7%	8%
New York City - Reference	40%	46%	48%	59%	54%	51%	1%	1%	1%
- CPP		43%	51%		56%	48%		1%	1%
- CPPEXT		42%	52%		57%	47%		1%	1%
- CPPNUC		44%	51%		55%	48%		1%	1%
Long Island - Reference	10%	17%	12%	88%	76%	80%	2%	6%	8%
- CPP		16%	11%		78%	81%		7%	8%
- CPPEXT		14%	12%		81%	79%		5%	10%
- CPPNUC		16%	12%		77%	80%		7%	8%
Upstate New York - Reference	70%	70%	72%	26%	25%	23%	4%	5%	5%
- CPP		63%	57%		31%	33%		5%	10%
- CPPEXT		64%	59%		31%	28%		5%	13%
- CPPNUC		67%	58%		28%	33%		5%	9%
Mid-Atlantic - Reference	71%	64%	60%	27%	34%	37%	2%	2%	3%
- CPP		65%	47%		33%	46%		2%	7%
- CPPEXT		62%	45%		33%	47%		5%	8%
- CPPNUC		65%	48%		33%	45%		2%	8%
Lower Michigan - Reference	82%	64%	64%	15%	31%	29%	3%	5%	7%
- CPP		59%	51%		30%	27%		11%	22%
- CPPEXT		58%	49%		21%	28%		21%	22%
- CPPNUC		59%	50%		31%	29%		10%	21%
Great Lakes - Reference	89%	90%	88%	9%	6%	9%	2%	3%	3%
- CPP		88%	76%		6%	5%		6%	19%
- CPPEXT		87%	74%		7%	6%		7%	20%
- CPPNUC		89%	76%		6%	5%		6%	19%
Mississippi Delta - Reference	54%	57%	46%	46%	43%	54%	0%	0%	0%
- CPP		45%	36%		55%	63%		0%	1%
- CPPEXT		43%	35%		56%	64%		1%	1%
- CPPNUC		41%	40%		58%	60%		0%	1%
Mississippi Basin - Reference	94%	94%	90%	2%	2%	6%	3%	4%	4%
- CPP		85%	71%		6%	6%		9%	23%
- CPPEXT		84%	70%		5%	6%		10%	24%
- CPPNUC		85%	72%		5%	6%		10%	22%
Southeast - Reference	61%	66%	66%	39%	34%	34%	0%	0%	0%
- CPP		58%	45%		42%	52%		0%	3%
- CPPEXT		56%	42%		44%	58%		0%	0%
- CPPNUC		60%	51%		40%	49%		0%	0%

Table 16. Regional generation shares by fuel category, baseline and Clean Power Plan cases, continued

	Onsite fuel			Real-time fuel			Intermittent		
Region - Case	**2013**	**2020**	**2030**	**2013**	**2020**	**2030**	**2013**	**2020**	**2030**
Tennessee Valley - Reference	89%	90%	86%	11%	10%	13%	0%	0%	1%
- CPP		85%	82%		12%	9%		4%	9%
- CPPEXT		85%	80%		12%	8%		3%	12%
- CPPNUC		86%	91%		12%	8%		1%	2%
Virginia Carolina - Reference	79%	83%	81%	21%	15%	16%	0%	2%	3%
- CPP		72%	67%		26%	21%		2%	12%
- CPPEXT		74%	68%		23%	18%		3%	14%
- CPPNUC		72%	67%		25%	22%		3%	11%
Central Plains - Reference	80%	79%	78%	7%	4%	5%	13%	16%	16%
- CPP		79%	73%		5%	5%		16%	22%
- CPPEXT		79%	72%		5%	6%		16%	23%
- CPPNUC		79%	73%		5%	5%		16%	22%
Southern Plains - Reference	54%	48%	45%	36%	32%	37%	11%	20%	18%
- CPP		33%	32%		45%	28%		21%	40%
- CPPEXT		34%	31%		44%	30%		23%	39%
- CPPNUC		32%	32%		47%	28%		20%	40%
Southwest - Reference	64%	60%	60%	33%	31%	31%	3%	9%	9%
- CPP		44%	46%		47%	31%		9%	23%
- CPPEXT		44%	47%		45%	33%		10%	20%
- CPPNUC		44%	46%		47%	33%		9%	22%
California - Reference	35%	35%	32%	55%	50%	53%	10%	16%	16%
- CPP		35%	34%		48%	50%		16%	16%
- CPPEXT		37%	34%		44%	48%		19%	18%
- CPPNUC		35%	33%		49%	51%		16%	16%
Northwest - Reference	78%	82%	76%	14%	8%	15%	8%	10%	10%
- CPP		79%	74%		11%	11%		10%	16%
- CPPEXT		78%	73%		11%	11%		10%	16%
- CPPNUC		79%	73%		11%	11%		10%	16%
Rocky Mountain - Reference	73%	76%	64%	16%	11%	20%	11%	13%	16%
- CPP		62%	56%		20%	12%		18%	32%
- CPPEXT		62%	53%		19%	15%		18%	32%
- CPPNUC		63%	56%		20%	12%		18%	32%

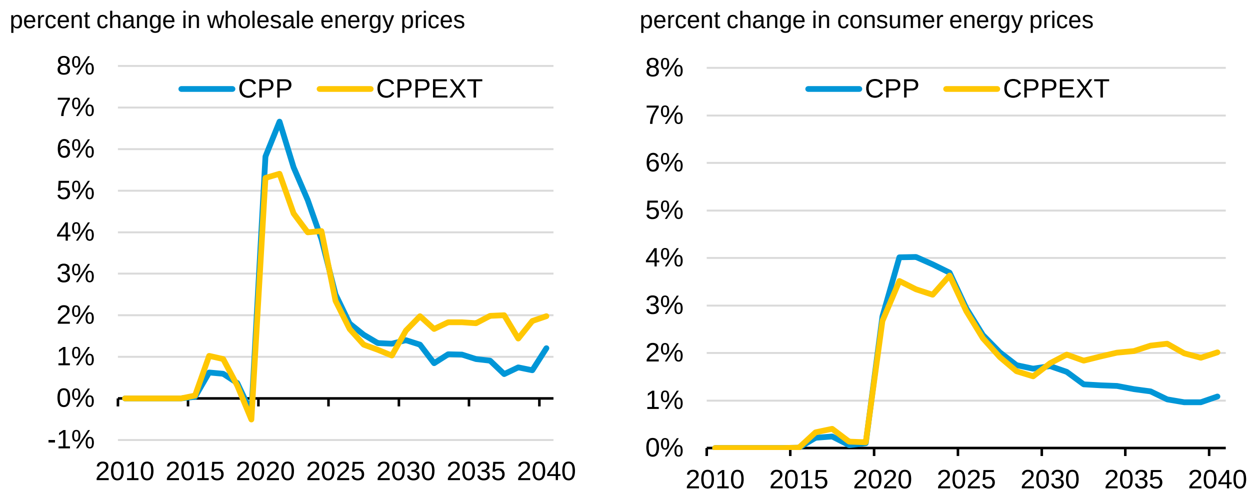
Source: U.S. Energy Information Administration.

Macroeconomic indicators

Under the Clean Power Plan, energy price changes and incremental investment needed to reach emission performance goals determine economic impacts. Resources must be diverted in order to fund technologies that would not have been used if the emission performance goals had not been imposed. These factors result in fewer available resources to produce other goods and services. The cost of energy efficiency improvements financed through utility programs is also reflected in energy prices, but consumer bills also reflect the savings associated with lower electricity consumption.

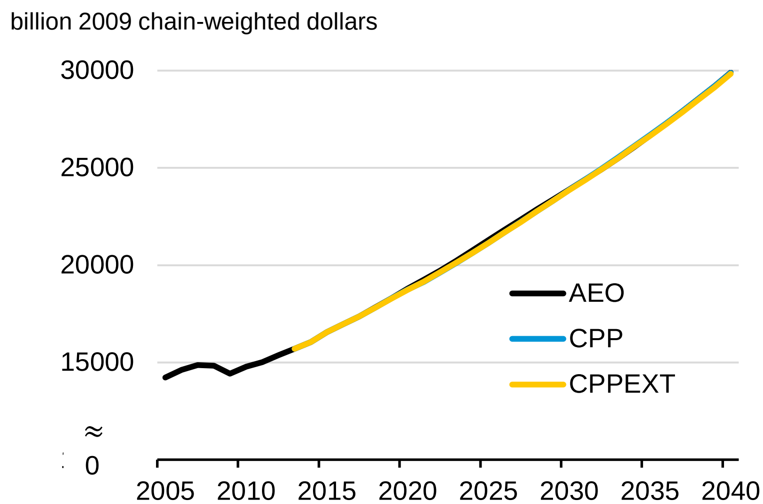
Economic activity, when measured either by real gross domestic product (GDP), industrial shipments, or consumption, is lower under the Base Policy case (CPP) than for the Reference case (AEO). Energy prices are higher, and more investment is needed in order to produce electricity from low- and zero-carbon sources under the Base Policy case (CPP). The economic impacts across the policy cases, when compared with the relevant baseline case, reduce cumulative GDP over the 2015-40 period by 0.15%-0.25%. The Policy Extension case (CPPEXT) causes larger reductions in GDP and disposable income than the Base Policy case (CPP). Figure 37 shows the pattern of industrial and consumer energy prices which drive much of the difference in economic impacts. Figure 38 shows that the level of GDP in the CPP and CPPEXT cases is almost indistinguishable from that projected in the AEO2015 Reference case that serves as their baseline. GDP growth trends in all cases are dominated by workforce and productivity drivers that are not influenced by the proposed Clean Power Plan. Figure 39 and Figure 40 provide an alternative perspective on the same information by respectively displaying effects of the Base Policy case (CPP) and the Policy Extension case (CPPEXT) on cumulative GDP and cumulative disposable income. As shown in these figures, cumulative impacts over the 2015-40 period are in the hundreds of billions of dollars, equivalent to changes of a few tenths of 1 percent from baseline given the magnitude of GDP and disposable income accumulated over the 2015-40 period.

Figure 37. Wholesale and consumer energy price changes across two Clean Power Plan cases, relative to AEO2015 Reference case



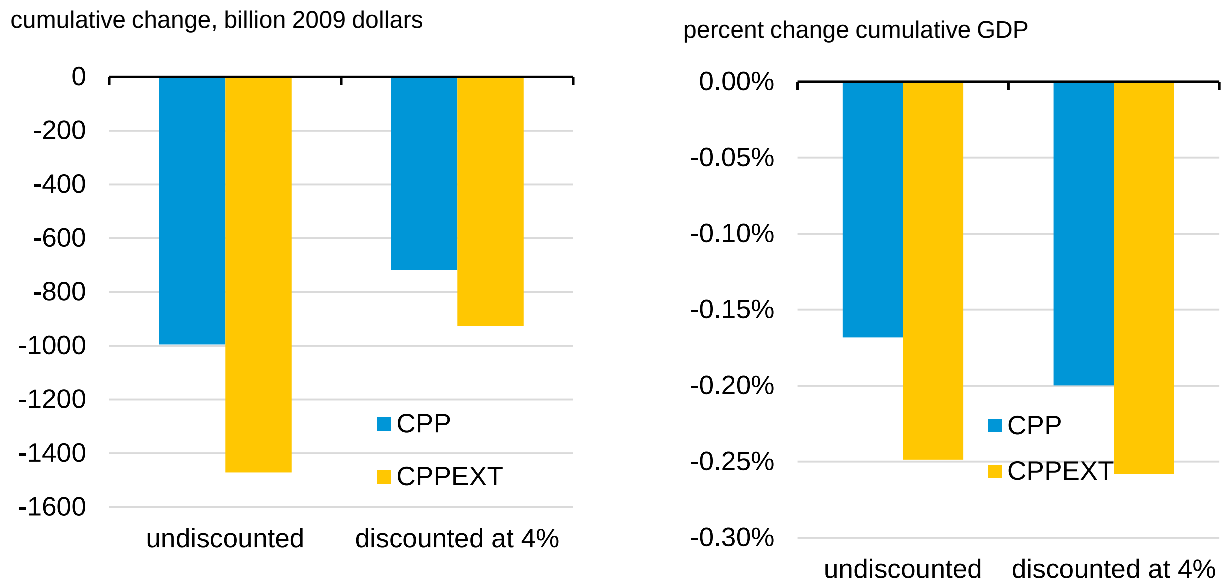
Source: U.S. Energy Information Administration.

Figure 38. Real gross domestic product in AEO2015 Reference and Clean Power Plan cases, 2015-40



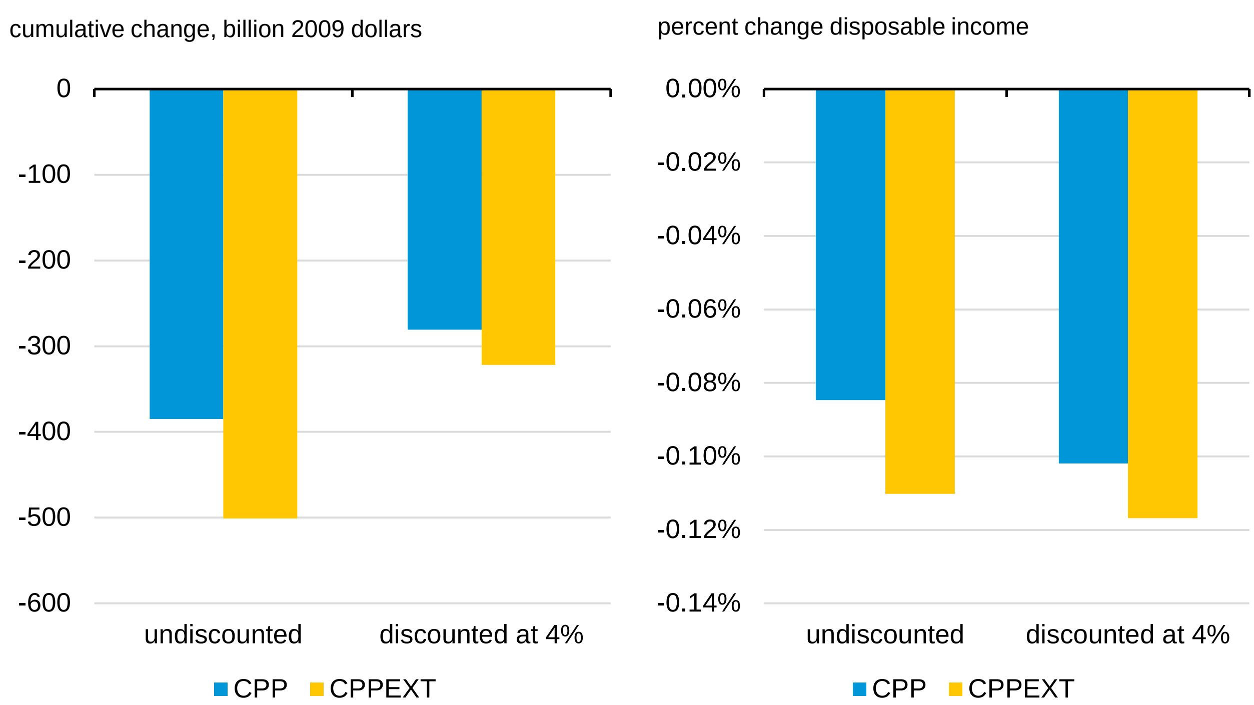
Source: U.S. Energy Information Administration.

Figure 39. Real cumulative GDP impacts across two Clean Power Plan cases, relative to AEO2015 Reference case



Source: U.S. Energy Information Administration.

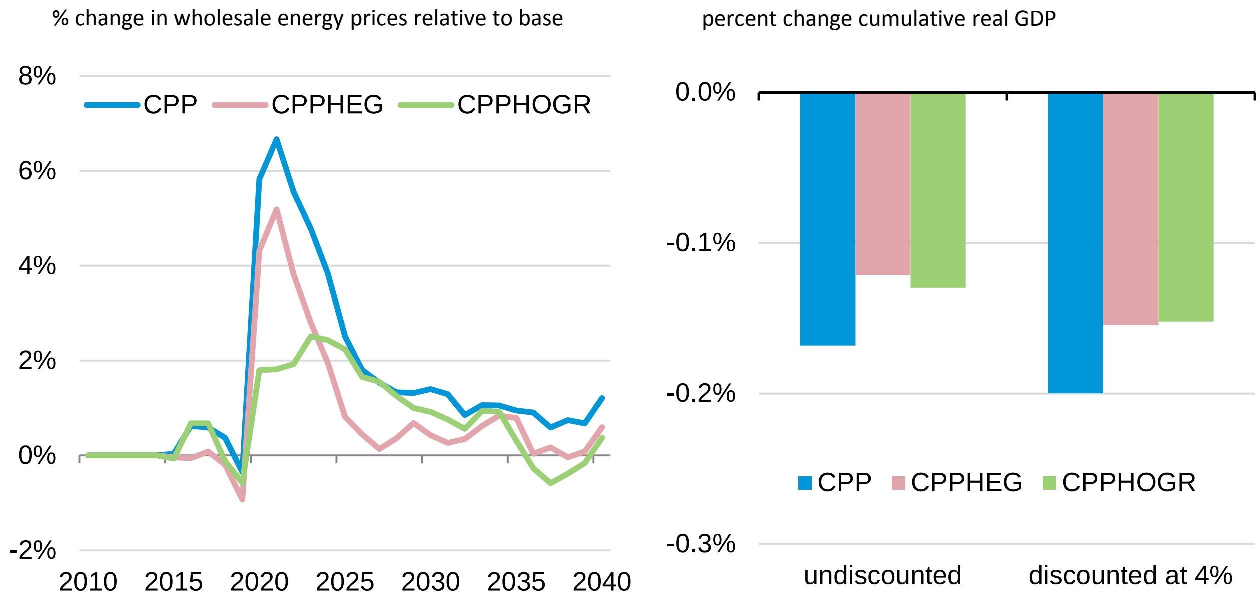
Figure 40. Disposable income changes across two Clean Power Plan cases, relative to AEO2015 Reference case



Source: U.S. Energy Information Administration.

Implementing the Clean Power Plan under conditions that assume high economic growth (CPPHEG) or high oil and gas resources (CPPHOGR) ameliorate both GDP and disposable income impacts relative to outcomes using the respective baseline cases. For the Base Policy case (CPP) Industrial energy price changes peak at 7% above the AEO2015 Reference case, compared with 5% above baseline for the High Economic Growth case (CPPHEG) and 2.5% above baseline for the High Oil and Gas Resource case (CPPHOGR). Figure 41 highlights this correspondence between energy price changes and economic impacts, with cumulative GDP impacts over the 2015-40 period deviating slightly from their respective reference cases.

Figure 41. Change in wholesale energy prices and real GDP in Clean Power Plan cases relative to baseline



Source: U.S. Energy Information Administration.

Additional sensitivity cases

This section of the report discusses additional sensitivity cases beyond the main Clean Power Plan cases previously analyzed. Table 17 describes each additional sensitivity case in detail.

Table 17. Additional Clean Power Plan sensitivity cases

Case name	Description
Policy with TSD Phase-in (CPPTSDPH)	The Policy with TSD Phase-In case models the Clean Power Plan relative to the AEO2015 Reference case. The case differs from the Base Policy case by assuming the state phase-in paths from Appendix 1 of EPA's Goal Computation Technical Support Document (TSD), without modification. The phase-in paths in the Goal Computation TSD tend to represent larger reductions in the early compliance years, compared with the phase-in paths assumed in the bulk of this analysis.
Policy with High HRI (CPPHRIHI)	The Policy with High HRI case models the Clean Power Plan assuming higher levels of heat rate improvement (HRI) potential and associated cost. The CPPHRIHI case is compared with a modified Reference case (AEOHRIHI) that uses the same heat rate improvement parameters.
Policy with Low HRI (CPPHRILO)	The Policy with Low HRI case models the Clean Power Plan assuming lower levels of heat rate improvement potential and associated cost. The CPPHRILO case is compared with a modified Reference case (AEOHRILO) that uses the same heat rate improvement parameters.
Policy with No EE (CPPEENO)	The Policy with No EE case models the Clean Power Plan assuming that energy efficiency is not used as a compliance mechanism, without modification to state emission performance goals. The baseline for the CPPEENO case is the AEO2015 Reference case.
Policy with High EE (CPPEEHI)	The Policy with High EE case models the Clean Power Plan assuming that demand-side energy efficiency is subsidized more heavily, relative to the Base Policy case. The baseline for the CPPEEHI case is the AEO2015 Reference case.
Policy with No EOR (CPPEORNO)	The Policy with No EOR case models the Clean Power Plan assuming no market for CO_2 from the electric power sector for enhanced oil recovery purposes. The baseline for the CPPEORNO case is the AEO2015 Reference case.
Policy with National Cooperation (CPPUS)	The Policy with National Cooperation case models the Clean Power Plan assuming that EMM regions group together to form a compliance region consisting of the entire lower 48 states. The baseline for the CPPUS case is the AEO2015 Reference case.
Policy with Limited Trade (CPPLIMTR)	The Policy with Limited Trade case constrains transmission capacity between regions, resulting in a scenario that limits increases in interregional flows as a compliance strategy to meet Clean Power Plan requirements. The baseline for the CPPLIMTR case is the AEO2015 Reference case.

Phase-in sensitivity

The Clean Power Plan contains interim emission performance goals, which must be met on average from 2020-29. EPA allows the flexibility in choosing annual targets, as long as the averages over the period correspond to the interim goals. EPA's Goal Computation Technical Support document included an appendix with calculated annual goals for each state, illustrating a potential path to meeting the interim goals.

The cases in this analysis use an alternate phase-in path that imposes less stringent targets in the initial years but modifies the subsequent rates to maintain interim 2020-29 compliance goals. However, the Base Policy with TSD Phase-in (CPPTSDPH) case phases in emission performance goals exactly as published in EPA's Goal Computation Technical Support Document. This case was examined in order to evaluate the impacts of alternate phase-in choices.

In 2020 the electricity price in the CPPTSDPH case is 8% higher than the Reference case, compared with a 5% higher electricity price in the Base Policy case. This difference reflects the greater "shock to the system" at the start of implementation when affected states and regions do not take advantage of the flexibility to phase in implementation more gradually while still meeting the specified average interim goals for 2020-29. The initial impact on renewable generation is minimal because the capability to increase renewable capacity is limited in the short term due to the lead times associated with building new capacity.

Table 18. Summary of Key Indicators in phase-in case

	Reference	CPP	CPPTSDPH
Heat Rate Improvement (gigawatts)			
2020	7	68	83
2030	13	74	89
2040	13	75	93
Heat Rate Improvement (percent) *			
2020	-1.1	-2.8	-3.8
2030	-1.1	-2.6	-3.5
2040	-1.1	-2.6	-3.3
Coal-Fired Generation Share (percent)			
2020	39.3	31.1	26.8
2030	36.5	25.1	25.4
2040	33.7	25.9	26.4
Gas-Fired Generation Share (percent)			
2020	25.7	32.1	36.4
2030	29.2	31.2	30.6
2040	31.0	29.5	28.4

Table 18. Summary of Key Indicators in phase-in case (cont.)

	Reference	CPP	CPPTSDPH
Renewable Generation Share (percent)			
2020	15.6	17.2	17.1
2030	16.1	25.2	25.5
2040	18.0	27.4	27.8
Energy Efficiency Savings (billion kilowatthours)			
2020	0	22	30
2030	0	81	85
2040	0	102	111
Electricity Price (2013 cents per kilowatthour)			
2020	10.5	11.0	11.4
2030	11.1	11.5	11.6
2040	11.8	12.1	12.3

*Heat rate improvement is relative to 2013 levels.
Source: U.S. Energy Information Administration.

Heat rate improvement sensitivity cases

The study that EIA used as a basis for modeling heat rate improvement in AEO2015 and in this report reflects a range of heat rate improvement potential and cost for each NEMS coal plant type and quartile grouping as described in Appendix F. The high end of the range generally represents higher heat rate improvement potential for a higher cost, while the low end generally represents lower improvement potential for lower cost. In this report, EIA uses a mid-range heat rate improvement estimate in the main Clean Power Plan cases and in the baseline cases.

However, to assess the impact of varying heat rate improvement assumptions, EIA also ran sensitivity cases using the high and low heat rate improvement estimates under both Reference and Base Policy cases. The Base Policy High HRI case uses the high end of the heat rate improvement potential and cost estimates, while the Base Policy Low HRI case uses the low-end estimates.

Table 19 displays heat rate improvement projections for coal-fired units under the Clean Power Plan in the sensitivity cases. For comparison, each Base Policy sensitivity case matches with its consistent baseline (for instance, the Base Policy High HRI case compares to a Reference case that uses high heat rate improvement potential and cost estimates).

Compared with the Base Policy case (CPP), the Policy with High HRI case (CPPHRIHI) projects greater heat rate improvement, on average, although less total capacity undertakes heat rate improvement measures. At the same time, there is more improvement realized per unit of capacity due to the higher potential of each activity. In the Policy with Low HRI case (CPPHRILO), less capacity undertakes heat rate improvement activity, and the average improvement across coal-fired generating units is lower as compared with the Base Policy case. The lower level for heat rate improvement potential in the Policy with Low HRI case results in the most modest levels of heat rate improvement compared with the underlying baseline.

Table 19. Comparison of heat rate improvement (HRI) indicators in three cases.

	Average heat rate for coal-fired units (Btu/kWh)			Percentage HRI relative to baseline			Gigawatts of capacity undertaking HRI (baseline)		
	2020	2030	2040	2020	2030	2040	2020	2030	2040
CPP	10,198	10,215	10,220	1.7%	1.5%	1.5%	68	74	75
							(7)	(13)	(13)
CPPHRIHI	10,153	10,144	10,175	2.3%	2.2%	1.8%	66	71	73
							(3)	(9)	(13)
CPPHRILO	10,290	10,317	10,345	0.9%	0.8%	0.6%	66	73	73
							(2)	(2)	(2)

Source: U.S. Energy Information Administration.

Energy efficiency sensitivity cases

This section further explores key demand-side results for the Base Policy case (CPP) along with two alternatives: a case without using the energy efficiency compliance option (CPPEENO) and a case with more aggressive subsidization of end uses (CPPEEHI). Overall the results demonstrate that within the analytic framework of this study, energy efficiency plays an important yet limited role in Clean Power Plan compliance. This is due to the presence of competing compliance options within a narrow range of incremental cost.

Table 20 summarizes the net present value of annual costs incremental to Reference case costs. In the Base Policy case, $110 billion of new capacity net present value (NPV) costs are accumulated through 2030 along with EE expenditures of $21 billion. Total sales are 2.5% lower than in the Reference case, and with increased renewable (wind) capacity and generation, fuel costs and non-fuel operating costs are $37 billion lower. Consumers across all sectors spend $59 billion more for electricity in 2030 in the Base Policy case relative to the Reference case as suppliers pass along the increased costs incurred in meeting Clean Power Plan requirements. After accounting for program incentives, consumers also spend approximately $2 billion on EE electrical equipment purchases that have been stimulated by both EE program subsidies and higher electricity prices. Consumers' natural gas bills are $18 billion higher as increased natural gas use by the power sector affects delivered prices to all users.

In the CPPEENO case, wind capacity costs substitute for expenditures on EE subsidies nearly one-for-one compared with the Base Policy case - cumulative NPV new capacity costs are $21 billion higher and EE expenditures $21 billion lower in 2030 (Table 20). Due to the lack of subsidies, electricity sales are 56 BkWh higher in 2030 (not cumulative), since sales are not being directly impacted by energy efficiency savings, and the only incentive for more-efficient purchases is the higher electricity prices relative to the Reference case. Fuel costs are $4 billion lower in the CPPEENO case due to the increased wind generation, and total power sector costs net to a $3 billion decrease relative to the Base Policy case. Electricity expenditures by all consumers are $5 billion lower and the increased wind generation reduces the pressure on natural gas-fired generation, which mitigates the price rise for natural gas in the CPPEENO case, reducing consumer natural gas expenditures by $3 billion relative to the Base Policy case.

Table 20. Incremental cumulative net present value of selected costs (billion 2013 $) over 2014-40 relative to AEO2015 Reference case[33]

	CPP			CPPEENO			CPPEEHI		
	2020	2030	2040	2020	2030	2040	2020	2030	2040
New capacity	5	110	164	9	131	195	4	97	140
Retrofits	0	7	9	0	6	8	0	7	9
Non-fuel operating costs	-4	-9	-10	-3	-6	-6	-5	-12	-16
Fuel costs	7	-28	-64	4	-32	-69	7	-35	-76
EE expenditures by electric power sector	2	21	32	0	0	0	8	62	92
Consumer costs of EE expenditures[34]	0	2	1	0	0	0	-1	-9	-14
Consumer electricity bills	9	59	63	7	54	65	12	76	79
Consumer natural gas bills	7	18	19	6	15	14	7	14	14

Source: U.S. Energy Information Administration.

For the CPPEEHI case, 2030 cumulative NPV power sector costs are $17 billion greater than for the Base Policy case. Lower cumulative NPV capacity and operating costs are not enough to offset the additional $41 billion in NPV cumulative EE expenditures through 2030. Electricity expenditures are $17 billion higher in the CPPEEHI case than the Base Policy case as the additional power sector costs are passed along to consumers. Lower electricity sales reduce the pressure on natural gas-fired generation and prices in this case, reducing natural gas expenditures by $4 billion relative to the Base Policy case.

Markets for CO_2 for enhanced oil recovery

Carbon dioxide can be injected into oil fields to enhance oil recovery (EOR) so this can represent an incentive to either retrofit or build new generating capacity with carbon capture and sequestration (CCS) equipment. CCS also represents another potential option for reducing the average CO_2 emission rate. An alternate case was examined, in which there was no market for CO_2 from electric power plants for EOR.

In the AEO2015 Reference case, one gigawatt of new capacity with CCS is added. In the Base Policy case, four gigawatts of existing coal-fired plants are retrofitted with CCS due to the combination of the EOR incentive and contribution towards lowering the average CO_2 emission rate. Upon removal of the incentive to capture CO_2 for EOR, the additional CCS retrofits do not occur.

[33] Costs are incremental to the cumulative NPV of resource costs in the Reference case. NPV calculations for this table use an 8% discount rate.

[34] Approximate incremental consumer investment in energy-efficient technologies.

Table 21. Total capacity with carbon capture and sequestration in three cases (gigawatts)

	AEO	CPP	CPPEORNO
2020	1	2	1
2030	1	5	1
2040	1	5	1

Source: U.S. Energy Information Administration.

Wide regional cooperation

The Clean Power Plan specifies a set of goals for each state. In this analysis, the state goals are converted to regional goals for the 22 NEMS EMM regions. In the Base Policy case, each region is required to meet its own standards. To examine the impacts of greater interregional cooperation, the Policy with National Cooperation case models all 22 electricity regions as a single national compliance region.

Compared with the Base Policy case, the CPPUS case results in more renewable capacity and generation as areas with abundant, economic supplies can increase the contribution of zero-carbon electricity supplies. This, in turn, reduces the need to switch from coal to natural gas and invest in energy efficiency.

Cooperation among regions also lowers electric power sector resource costs, which include investment costs (new capacity, transmission, retrofits, and energy efficiency) and operating expenditures (operating and maintenance, fuel, and power purchases). Table 22 shows the difference in total electric power sector resource costs between the Base Policy case and the CPPUS case. Note, however, that the CPPUS case is only included as a sensitivity to bound the total compliance cost savings achievable through cooperation. Issues such as interregional cost allocation, which would be needed to achieve wide cooperation, were not addressed in this analysis. Therefore, no regional results are presented for the CPPUS case.

Table 22. Electric power sector resource costs in three cases - cumulative net present value over 2014-40 (billion 2013 dollars)

	AEO	CPP	CPPUS
2020	891	902	900
2030	1,561	1,662	1,647
2040	1,928	2,058	2,034

Source: U.S. Energy Information Administration.

Biomass CO_2 emission rate

In its analysis of the Clean Power Plan, the EPA assumes that biomass consumption has an emission rate for CO_2 of 195 pounds per MMBtu consumed. The biomass fuels represented in the EIA analysis are primarily waste products and agricultural and forestry feedstock, which are assumed to be carbon-neutral over the fuel lifecycle.

In the AEO2015 Reference case, dedicated biomass capacity in the electric power sector totals five gigawatts by 2040. In the Base Policy case, an additional three gigawatts are built. However, in the Policy with Biomass CO_2 (CPPBIO195) case, which uses the EPA emission rate for CO_2 of 195 pounds per MMBtu, no biomass capacity additions occur. Generation from dedicated biomass plants in 2040 increases by 58% in the Base Policy case relative to the Reference case, but declines by 66% in the CPPBIO case when there are no new builds. In both CPP cases biomass generation from co-firing is lower than in the Reference case, due to increased coal retirements and lower use of coal capacity.

Table 23. Electric power sector biomass capacity and generation projections in three cases

	AEO	CPP	CPPBIO195
Biomass capacity (gigawatts)			
2020	3	5	3
2030	4	7	3
2040	5	8	3
Dedicated biomass generation (billion kWh)			
2020	13	26	7
2030	17	37	6
2040	30	48	10
Biomass co-firing generation (billion kWh)			
2020	11	9	9
2030	24	2	6
2040	28	7	17

Source: U.S. Energy Information Administration.

Limited interregional transmission capacity

One issue in modeling the Clean Power Plan implementation relates to interregional power flows. Available data show that significant power already flows between the regions represented in EIA's model. Model runs, whether for baseline or policy cases, allow for increases in interregional power flows and reflect the cost of added transmission that may be required to accommodate such flows in electricity prices. Interregional transmission capacity is generally projected to increase in the three AEO2015 cases (Reference, High Economic Growth, and High Oil and Gas Resources) used as baselines for implementation of the Clean Power Plan in this study. Interregional power flows and transmission capacity generally increase beyond baseline levels in model runs that implement the Clean Power Plan.

Even though interregional power flows already exist, the increase above baseline in trade in the Clean Power Plan cases could be viewed by some analysts as a form of interregional compliance cooperation. To explore the importance of trade to compliance, EIA developed the CPPLIMTR case as a sensitivity that is identical to the CPP case except that interregional transmission flows are held below the baseline (AEO reference case) level.

In the CPPLIMTR case, aggregate interregional flows are considerably lower than in the CPP case, where existing transfer capability is utilized more heavily and more interregional transmission capacity is added compared with the baseline AEO case. Relative to the CPP case, the more restrictive interregional trade assumption in the CPPLIMTR case results in a slight reduction in reliance on wind generation for compliance, reflecting a reduced capability to move power from regions with attractive wind resources to regions with less wind resource potential. The regions that have less wind resource potential generally compensate for lower interregional electricity supply in the CPPLIMTR case through a combination of increased within-region natural gas-fired and/or other renewable generation. Increased solar PV is an important source of in-region renewable generation in some of these areas.

While the results of the CPP and CPPLIMTR cases differ significantly for some regions, key indicators such as electricity prices, coal plant retirements, and reliance on coal, renewables, and natural gas are very similar when considered at the national level. Price results for both the CPP and CPPLIMTR cases, as well as the baselines against which they are compared, necessarily reflect the way in which prices and costs of interregional generation and transmission capacity are allocated across regions within the model.

Appendix A

Request letter

LAMAR S. SMITH, Texas
CHAIRMAN

EDDIE BERNICE JOHNSON, Texas
RANKING MEMBER

Congress of the United States
House of Representatives
COMMITTEE ON SCIENCE, SPACE, AND TECHNOLOGY
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August 13, 2014

The Honorable Adam Sieminski
Administrator
Energy Information Administration
U.S. Department of Energy
1000 Independence Avenue, SW
Washington, D.C. 20585

Dear Administrator Sieminski,

As the Administration considers regulations to reduce carbon emissions from fossil-fired power plants, the need for robust, objective, and well-grounded technical analysis of impacts on the American economy is imperative. The Environmental Protection Agency (EPA) has performed some analysis of its proposed Emissions Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Utility generating Units. Setting aside key legal and technical problems with EPA's novel approach to setting standards, EPA's compliance modeling disregards a number of confounding factors and broader economy-wide impacts.

We applaud the Energy Information Administration (EIA) for providing credible, transparent historical analyses over the years. As a result, we request that EIA analyze the impacts of the proposed guidelines using the specifications provided below. Given the magnitude of EPA's proposal, an expedited process would be greatly appreciated.

Because multiple analyses are important for understanding the possible impacts of the proposal, we are simultaneously asking EPA to re-run its model using the same specifications. This will allow for a side-by-side comparison of results. As requested of EPA, please provide your analysis by September 15, 2014. My staff is available to work with you to clarify any questions. Thank you for your prompt attention to this critical matter.

Sincerely,

Lamar Smith

Lamar Smith
Chairman
Committee on Science, Space, and
Technology

cc: Gina McCarthy, Administrator, Environmental Protection Agency
Eddie Bernice Johnson, Ranking Member, Committee on Science, Space, and Technology

Specifications for Analysis

Baseline Case:

The analysis should be based on EIA's Annual Energy Outlook 2014 (AEO2014) through 2040: baseline case "No GHG Concerns."

Policy Case:

Target reductions: 26% by 2020; 30% by 2030; 45% by 2040.

Alternative Policy Case:

Target reductions: 26% by 2020; 30% by 2030; 45% by 2040. Emissions reduction strategies limited to EPA "Building Blocks" 1 and 2 (heat rate improvement; dispatch changes among affected EGUs).

Sensitivity Analyses:

Run on both the Policy Case and Alternative Policy Case described above.

1. Accelerated nuclear retirement pursuant to the AEO 2014 side case;
2. Low natural gas supply pursuant to AEO 2014;
3. High LNG exports: 10 bcf/d by 2020, 15 bcf/d by 2025, and 20 bcf/d by 2030 from Gulf Coast and Atlantic Coast LNG terminals;
4. No market for EGU generated CO2; and
5. Aggregate of S1+S2+S3+S4.

Model Output and Analysis (state, regional, and national annual data):

All price point information should be reported in both real and nominal dollars.

1. Disposable income.
2. Jobs impact.
3. Greenhouse gas emissions - CO2 from electric generation, accounting for power plant fuel supply methane leakage.
4. National, regional electric markets, aggregation in NERC regions in 2005 base, 2012, 2015-2040.
5. Coal plants retired: 2005 base, 2012, 2015-2040.
6. Reserve margins in NERC regions.

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7. Natural gas supply, accounting for LNG exports.

8. Natural gas prices: domestic, LNG in Europe, LNG in Asia-Pacific.

9. Incremental infrastructure costs: electric transmission, natural gas infrastructure, CO2 infrastructure.

10. Costs: electricity, natural gas to non-electric users.

11. Stranded capital costs by year, aggregate.

12. Cost of power in baseline case and cost of power in Alternative Policy Cases from new plants.

13. Renewables: capacity, % in each NERC region, capacity factors, supplemental backup (spinning reserve), regional loss of load probability (LOLP) analysis.

14. NEMS natural gas information, including:
    a. Supply curve in AEO 2014, data used to validate new module, results of model validation;
    b. Retrospective analysis (projections vs. actual) for wellhead prices, production, and net imports: specifically, AEO2008, AEO 2010, AEO 2012; and
    c. Results of Stanford Energy Modeling Forum critiques/evaluation.

15. MAGICC analysis of sea level rise and global temperature for assume climate sensitivities of 3.0, 1.5. 1.0 for:
    a. Baseline case using U.S. CO2 emissions through 2040 and Rest of World (ROW) emissions from IEO 2013; and
    b. Policy Case of 30% power plant emission reductions through 2030 and 45% in 2040.

16. Social Cost of Carbon analysis through 2040 using the U.S. emissions through 2040, ROW emissions from IEO2013:
    a. FUND and DICE models results using Climate sensitivities 3.0, 1.5, 1.0;
    b. Provide results based on the use of a domestic-only social cost of carbon for 3% and 7% discount factors; and
    c. Provide the predicted sea level rise and temperature for each year.

3

Appendix B

Acronyms

Acronym	Definition
AEO	Annual Energy Outlook Reference case
AEO2015	Annual Energy Outlook, 2015 edition
AEOHEG	Annual Energy Outlook High Economic Growth case
AEOHOGR	Annual Energy Outlook High Oil and Gas Resource case
AEOHRIHI	Revised Reference case using higher heat rate improvement assumptions
AEOHRILO	Revised Reference case using lower heat rate improvement assumptions
AZNM	WECC / Southwest (EMM region)
BkWh	billion kilowatthours
BSER	Best System of Emissions Reduction
Btu/kWh	heat rate: commonly stated in British thermal units (Btu) per kilowatt-hour (kWh)
CAIR	Clean Air Interstate Rule
CAMX	WECC / California (EMM region)
CCS	carbon capture and sequestration
CHP	combined heat and power
CO_2	carbon dioxide
CPP	Base Policy case - Clean Power Plan modeling scenario
CPPBIO195	Policy with Biomass CO_2 case
CPPEXT	Policy Extension case modeling scenario
CPPHEG	Policy with High Economic Growth case
CPPEEHI	Policy with High Energy Efficiency case
CPPHRIHI	Policy with High Heat rate Improvement case
CPPHOGR	Policy with High Oil and Gas Resource case
CPPHRILO	Policy with Low Heat rate Improvement case
CPPEENO	Policy with no Energy Efficiency case
CPPEORNO	Policy with no EOR market case
CPPLIMTR	Policy with Limited Trade case
CPPNUC	Policy with New Nuclear case
CPPTSDPH	Policy with TSD-phase in case
CPPUS	Policy with National Cooperation case
CSAPR	Cross-State Air Pollution Rule
ECP	Electricity Capacity Planning
EE	Energy Efficiency
EIA	U.S. Energy Information Administration
EMM	Electricity Market Module
EOR	enhanced oil recovery
EPA	U.S. Environmental Protection Agency

Acronym	Definition
ERCT	Texas Regional Entity (EMM region)
FGD	flue-gas desulfurization
FRCC	Florida Reliability Coordinating Council (NERC, EMM region)
GDP	gross domestic product
GW	gigawatts (1000 MW): a measure of capacity
HRI	Heat rate improvement
IGCC	Integrated Gasification Combined Cycle
kWh	kilowatthour(s)
lbs CO_2/MWh	pounds of carbon-dioxide per megawatt-hour: carbon intensity measure
MRO	Midwest Reliability Organization (NERC regional entity)
MROE	Midwest Reliability Organization / East (EMM region)
MROW	Midwest Reliability Organization / West (EMM region)
MWh	megawatt-hour(s) / megawatthour(s)
NEMS	National Energy Modeling System
NEWE	NPCC / New England (EMM region)
NGCC	natural gas combined cycle (type of generating unit)
NPCC	Northeast Power Coordinating Council (NERC regional entity)
NPV	net present value
NWPP	WECC / Northwest Power Pool (EMM region)
NYCW	NPCC / NYC-Westchester (EMM region)
NYLI	NPCC / Long Island (EMM region)
NYUP	NPCC / Upstate New York (EMM region)
RFC	ReliabilityFirst Corporation (NERC regional entity)
RFCE	ReliabilityFirst Corporation / East (EMM region)
RFCM	ReliabilityFirst Corporation / Michigan (EMM region)
RFCW	ReliabilityFirst Corporation / West (EMM region)
RMPA	WECC / Rocky Mountain (EMM region)
RPS	renewable portfolio standard(s)
SERC	SERC Reliability Corporation (NERC regional entity)
SPNO	Southwest Power Pool / North (EMM region)
SPP	Southwest Power Pool (RTO; NERC regional entity)
SPSO	Southwest Power Pool / South (EMM region)
SRCE	SERC / Central (EMM region)
SRDA	SERC / Delta (EMM region)
SRGW	SERC / Gateway (EMM region)
SRSE	SERC / Southeastern (EMM region)
SRVC	SERC / Virginia-Carolina (EMM region)
TSD	EPA's Goal Computation Technical Support Document
WECC	Western Electricity Coordinating Council (NERC regional entity)

Appendix C

State carbon intensity targets

Table 24 displays the interim and final state goals that were used to model the Clean Power Plan in this analysis, as well as rates based on the 2012 historical data that were used to develop the targets. The 2012 fossil emission rate is based solely on 2012 fossil emissions and generation (and is not adjusted for other affected generators included in the goals, such as qualifying renewable and at-risk nuclear generation). An adjusted 2012 rate, reflecting the average emission rate including all affected generation, as defined by the Clean Power Plan is shown in the second column.

Table 24. EPA's proposed Clean Power Plan state carbon intensity targets (pounds CO_2 per megawatthour)[35]

State	2012 Fossil Emission rate	2012 CPP affected rate	Interim Goal (2020-2029 average)	Final Goal (2030 and beyond)
Alabama	1,518	1,444	1,147	1,059
Alaska	1,368	1,351	1,097	1,003
Arizona	1,551	1,453	735	702
Arkansas	1,722	1,634	968	910
California	900	698	556	537
Colorado	1,959	1,714	1,159	1,108
Connecticut	844	765	597	540
Delaware	1,255	1,234	913	841
Florida	1,238	1,199	794	740
Georgia	1,598	1,500	891	834
Hawaii	1,783	1,540	1,378	1,306
Idaho	858	339	244	228
Illinois	2,189	1,894	1,366	1,271
Indiana	1,991	1,924	1,607	1,531
Iowa	2,197	1,552	1,341	1,301
Kansas	2,320	1,940	1,578	1,499
Kentucky	2,166	2,158	1,844	1,763
Louisiana	1,533	1,455	948	883
Maine	873	437	393	378
Maryland	2,029	1,870	1,347	1,187
Massachusetts	1,001	925	655	576
Michigan	1,814	1,690	1,227	1,161
Minnesota	2,013	1,470	911	873
Mississippi	1,140	1,093	732	692

[35] Goal Computation Technical Support Document at Appendix 1, accessed December 29, 2014.

Table 24. EPA's proposed Clean Power Plan state carbon intensity targets (pounds CO_2 per megawatthour) (cont.)

State	2012 Fossil Emission rate	2012 CPP affected rate	Interim Goal (2020-2029 average)	Final Goal (2030 and beyond)
Missouri	2,010	1,963	1,621	1,544
Montana	2,439	2,246	1,882	1,771
Nebraska	2,162	2,009	1,596	1,479
Nevada	1,091	988	697	647
New Hampshire	1,119	905	546	486
New Jersey	1,035	928	647	531
New Mexico	1,798	1,586	1,107	1,048
New York	1,096	978	635	549
North Carolina	1,772	1,647	1,077	992
North Dakota	2,368	1,994	1,817	1,783
Ohio	1,897	1,850	1,452	1,338
Oklahoma	1,562	1,387	931	895
Oregon	1,081	717	407	372
Pennsylvania	1,627	1,531	1,179	1,052
Rhode Island	918	907	822	782
South Carolina	1,791	1,587	840	772
South Dakota	2,256	1,135	800	741
Tennessee	2,015	1,903	1,254	1,163
Texas	1,420	1,284	853	791
Utah	1,874	1,813	1,378	1,322
Virginia	1,438	1,302	884	810
Washington	1,379	756	264	215
West Virginia	2,056	2,019	1,748	1,620
Wisconsin	1,988	1,827	1,281	1,203
Wyoming	2,331	2,115	1,808	1,714

Source: U.S. Environmental Protection Agency, Office of Air and Radiation, *Goal Computation Technical Support Document*, Docket ID No. EPA-HQ-OAR-2013-0602 (June 2014), Appendix 1 - State level goals, underlying state level data, and calculations for The Proposed state goals, accessed December 29, 2014.

Appendix D

EMM Region carbon intensity targets

Table 25 displays the calculated interim and final carbon intensity goals for the Electricity Market Module regions, as used in this analysis. The 2012 historical generation-weighted average goal for each state in an EMM region was used as the basis for translating from EPA's state goals to EMM regional goals. The 2012 affected rate represents a measure of the current regional rate (estimated from modeled values), calculated based on affected generation defined by the Clean Power Plan.

Table 25. Electricity Market Module regional carbon intensity targets (pounds CO_2 per megawatthour)

Region*	2012 CPP affected rate	Interim Goal (2020-2029 average)	Final Goal (2030 and beyond)
Texas	1,411	855	793
Florida	1,097	794	740
Eastern Wisconsin	2,068	1,281	1,203
Northern Plains	1,816	1,362	1,308
New England	881	612	553
New York	1,108	635	549
Mid Atlantic	1,557	1,078	952
Lower Michigan	2,096	1,227	1,161
Great Lakes	2,002	1,496	1,395
Mississippi Delta	1,427	925	865
Mississippi Basin	2,202	1,462	1,374
Southeast	1,088	1,003	932
Tennessee Valley	1,757	1,391	1,317
Virginia Carolina	1,509	1,007	927
Central Plains	1,914	1,593	1,515
Southern Plains	1,669	940	890
Southwest	1,512	816	773
California	1,006	626	604
Northwest	1,656	1,081	1,017
Rocky Mountain	1,783	1,330	1,268

*See Figure 1 and Table 1 for description of EMM regions. Names are intended to be approximately descriptive of location. Exact regional boundaries do not necessarily correspond to state borders or to other regional naming conventions.
Source: U.S. Energy Information Administration

Appendix E

Detailed description of NEMS carbon intensity constraint

Equation 1 is a simplified version of the intensity constraint. When this constraint is binding in the Electric Capacity Planning model, its shadow price (in units of $/pound) represents the marginal cost for a region to take an action from among building blocks #1, #2 and #3 for Clean Power Plan compliance in a particular time period. When the constraint is binding in the Electricity Fuel Dispatch model (after the capacity decisions are in place), its shadow price represents the marginal cost of using building block #2 for compliance. As the use of building block #4 (energy efficiency) is determined through an iterative process with the NEMS Residential and Commercial Demand models, the capacity planning model does not optimize energy efficiency as a marginal compliance option.

Equation 1: Simplified representation of NEMS carbon intensity constraint

$$\sum_{i \in AFF} [\boldsymbol{g}_{yir}(\boldsymbol{f}_{ir} - \boldsymbol{h}_{yr})] - \sum_{i \in NUE} 0.06 \boldsymbol{g}_{yir} \boldsymbol{h}_{yr} - \sum_{i \in ZE} \boldsymbol{g}_{yir} \boldsymbol{h}_{yr} - \boldsymbol{d}_{yr} \boldsymbol{h}_{yr} \leq 0 \quad \forall y, r$$

where:

y – the index of compliance years
i – the index of generating capacity types
r – the index of EMM regions
AFF – the set of affected CO_2-emitting electric generating capacity types
NUE – the set of existing nuclear generating plants
ZE – the set of credited zero-carbon-emitting compliance options,
including existing and new renewables and nuclear plants already under construction
$\boldsymbol{f}_{ir}$ – carbon emissions rate of generating capacity type i
in EMM region r (pounds per megawatthour)
$\boldsymbol{g}_{yir}$ – generation in compliance year y from generating capacity type
i in EMM region r (megawatthours)
$\boldsymbol{h}_{yr}$ – emissions rate goal in compliance year y in EMM region r (pounds per megawatthour)
$\boldsymbol{d}_{yr}$ – energy efficiency savings in compliance year y in EMM region r (megawatthours)

It is uncertain how interregional trade should be accounted for in the intensity standards of both the exporting and importing regions. Although not explicitly shown in the simplified representation above, this analysis represents trade as a supply source with an intensity rate equal to the specified intensity standard of the exporting (i.e., producing) region. That is, it is equivalent to a plant with a carbon emission rate corresponding to the target specified for the exporter. This amount is then treated as affected generation in the importing region's intensity standard and excluded from corresponding generation in the exporting region.

Appendix F

Additional description of methodology for heat rate improvement, re-dispatch, low- and zero-carbon generation, and demand-side efficiency

Heat rate improvement

Heat rate is a measure of the thermal efficiency of an electric generating unit, commonly representing the amount of energy used to generate one kilowatthour of electricity.[36] A generating unit with a lower, or more-efficient, heat rate can generate the same quantity of electricity while consuming less fuel, compared with a unit with a higher heat rate.

The heat rate improvement potential for the existing coal-fired steam generating units represented in NEMS is based on a recent contractor study.[37] The study used a statistical analysis of the characteristics of coal-fired steam generating units to create predictive models for heat rates. The analysis underlying the study categorized coal-fired generating units according to plant characteristics, and assigned units to quartiles representing observed versus predicted heat rate performance. Units in the first quartile (Q1), which perform better than predicted, were generally considered to have the least potential for heat rate improvement. Units in the fourth quartile (Q4), representing the least-efficient units relative to predicted values, were generally considered to have the most potential for heat rate improvement.

The study then considered the application of heat rate improvement measures, and their associated costs, across combinations of plant types and improvement potential quartiles. Through a literature review and engineering expertise, the contractor developed a matrix of heat rate improvement measures and associated costs for combinations of plant types and quartiles. The study included minimum and maximum heat rate potential estimates, along with the associated costs.[38]

The contractor also provided EIA with an estimate of mid-range heat rate improvement potential and cost estimates, which are the default assumptions for the AEO2015 and for this analysis. Under these assumptions, across the fleet of existing coal-fired generators, the average attainable improvement potential is 4%, at an average capital cost of $300/kW.[39] However, there is significant variation across plant types and quartiles. Across 28 plant type-quartile combinations, potential for improvement ranges from 0% to 10%, with the associated capital costs ranging from $0 (no improvement available) to $1,000/kW.

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[36] U.S. Energy Information Administration, Frequently Asked Questions, What is the efficiency of different types of power plants?, accessed January 31, 2015.
[37] U.S. Energy Information Administration, *Analysis of Heat Rate Improvement Potential at Coal-Fired Power Plants*, (May 2015).
[38] The analysis selected the ECP type and quartile groupings such that each grouping contained at least 10 generating units, with the exception of the IG type, which has essentially no heat rate improvement potential. Some ECP types and quartiles also had associated variable O&M costs. The variable O&M costs were not incorporated into the NEMS EMM model at the time of this analysis. However, the impact of omitting variable O&M cost is expected to be small due to the relative magnitude of the capital and fixed O&M cost components.
[39] Costs expressed in 2014 dollars.

Re-dispatch

A central component of power systems scheduling and operations is the dispatch of electric generators. Dispatch refers to setting the power output level of electric generators in order to meet a variety of system requirements, including satisfying electricity demand, along with other constraints. Re-dispatch refers to changes in the dispatch configuration. The use of re-dispatch to shift utilization away from resources with higher carbon intensity, and towards those with lower carbon intensity (especially away from existing coal-fired generating units and towards existing natural gas combined cycle plants), is one available option for compliance with the proposed Clean Power Plan emissions targets.

EIA's NEMS model represents dispatch at the EMM regional level (see Figure 1). Within each NEMS EMM region, an economic dispatch algorithm finds the least-cost solution to meeting electricity demand, within modeled generator and system constraints. For this analysis, EIA added a carbon intensity constraint to the NEMS EMM model to represent regional emission performance goals, and to allow economic choice of the re-dispatch option. The carbon intensity constraint appears in the economic dispatch algorithms used by both the capacity planning and dispatch sub-modules of the EMM. This model structure simulates each region making economic tradeoffs between the use of re-dispatch, the use of heat rate improvement, and capacity expansion in order to achieve compliance in a least-cost manner. The use of energy efficiency, which is determined semi-endogenously through an iterative process with the NEMS Commercial and Residential Demand Modules, also factors into the intensity constraint. Appendix E describes the carbon intensity constraint in further detail.

Low- and zero-carbon capacity expansion

EIA's NEMS model represents economic and policy choices to expand low- and zero-carbon renewable electricity resources. NEMS includes state-level policies, such as renewable portfolio standards (RPS). For this analysis, there are no changes to EIA's AEO2015 Reference case assumptions regarding state RPS constraints, nor are there any changes to assumptions for cost or operational characteristics of renewable electricity resources. When modeling the Clean Power Plan, existing and new non-hydroelectric and non-municipal solid waste (MSW) renewable resources receive credit in the compliance calculation for each region.[40] Output from incremental new hydroelectric generating capacity also factors into the compliance calculation for each region.

NEMS represents the addition of nuclear plants currently under construction (Summer 2 and 3, Vogtle 3 and 4, and Watts Bar 2), and allows economic choices to add new nuclear plants in the future. The output from currently under construction nuclear plants is included in the compliance calculation for each region. In addition, 6% of generation from existing nuclear plants is included in the compliance calculation for each region, consistent with the proposed rule's provision to give states credit for preserving at-risk nuclear capacity.

The Clean Power Plan does not explicitly discuss credit for new nuclear power plants not already under construction in compliance calculations. As such, this analysis does not include output from unplanned new nuclear units in the regional compliance calculations for the Base Policy case. However, this report

[40] The net energy generated from these resources is included in the denominator of the (pounds CO_2 per megawatthour) carbon intensity calculation for each region, helping to lower the region's intensity, as zero-carbon generation does not contribute any CO_2 to the numerator.

contains an alternate case in which generation from unplanned new nuclear capacity is included in the compliance calculation.

Demand-side energy efficiency

EIA developed prototypical portfolios of energy efficiency program measures to represent and distribute energy efficiency program spending for the Clean Power Plan in the NEMS Residential and Commercial Demand Modules. Subsidies, in the form of direct rebates, decrease the installed capital cost of energy-efficient equipment, as is typical of utility incentives.[41] Subsidized end uses include space heating, space cooling, water heating, ventilation, lighting, refrigeration, and residential building envelopes. EIA assumes that energy efficiency portfolios vary by Census division in terms of the implementation, timing, and level of end-use subsidies.

For the purposes of this analysis, EIA calculates electricity savings as the difference between baseline residential and commercial electricity sales in the appropriate baseline case, and electricity sales to these sectors in the Clean Power Plan scenarios. EIA calculates utility expenditures as the total cost of all equipment rebates plus additional utility program costs. EIA assumes the additional program costs add 50% to the total cost of equipment rebates. Within NEMS, the Residential Demand Module and the Commercial Demand Module provide the Electricity Market Module with incremental energy efficiency program savings and costs by sector, Census division, and year for use in the regional compliance calculations.

EIA contracted to obtain information regarding current energy efficiency program activity for use in developing assumptions about common types of efficiency measures employed and variation in program spending by region and end use.[42] EIA categorized Census divisions as either “active” or “startup” based on current program activity.

Table 26 provides assumed rebate levels for efficiency measures and timing of implementation as part of the Clean Power Plan.

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[41] Modeling of federal equipment subsidies (e.g., federal tax credits) is achieved through different subsidy inputs than those used for this analysis to maintain the ability to model both types of rebates without over-counting equipment expenditures associated with utility savings.

[42] U.S. Energy Information Administration, *Analysis of Energy Efficiency Program Impacts Based on Program Spending*, (May 2015).

Table 26. End-use rebate level as a percentage of installed cost by energy efficiency program category and Census division as used for input to NEMS

	New England	Middle Atlantic	East North Central	West North Central	South Atlantic
Space heating	10% in 2017 15% in 2020	10% in 2017 15% in 2020	10% in 2017 15% in 2020	10% in 2017 15% in 2020	10% in 2017 15% in 2020
Space cooling	10% in 2017 15% in 2020	10% in 2017 15% in 2020	10% in 2017 15% in 2020	10% in 2017 15% in 2020	10% in 2017 15% in 2020
Water heating	15% in 2020	15% in 2020	15% in 2025	15% in 2025	15% in 2025
Ventilation (Commercial)	10% in 2020 15% in 2025	10% in 2020 15% in 2025	10% in 2020 15% in 2025	10% in 2020 15% in 2025	10% in 2020 15% in 2025
Lighting	10% in 2017 15% in 2020	10% in 2017 15% in 2020	10% in 2017 15% in 2020	10% in 2017 15% in 2020	10% in 2017 15% in 2020
Refrigeration	10% in 2020 15% in 2025	10% in 2020 15% in 2025	10% in 2020 15% in 2025	10% in 2020 15% in 2025	10% in 2020 15% in 2025
Building envelope (Residential)	15% in 2017	15% in 2017	15% in 2025	15% in 2025	15% in 2025
Efficiency program activity category	active	active	startup	startup	startup

	East South Central	West South Central	Mountain	Pacific
Space heating	10% in 2017 15% in 2020	10% in 2017 15% in 2020	10% in 2017 15% in 2020	10% in 2017 15% in 2020
Space cooling	10% in 2017 15% in 2020	10% in 2017 15% in 2020	10% in 2017 15% in 2020	10% in 2017 15% in 2020
Water heating	15% in 2025	15% in 2025	15% in 2020	15% in 2020
Ventilation (Commercial)	10% in 2020 15% in 2025	10% in 2020 15% in 2025	10% in 2020 15% in 2025	10% in 2020 15% in 2025
Lighting	10% in 2017 15% in 2020	10% in 2017 15% in 2020	10% in 2017 15% in 2020	10% in 2017 15% in 2020
Refrigeration	10% in 2020 15% in 2025	10% in 2020 15% in 2025	10% in 2020 15% in 2025	10% in 2020 15% in 2025
Building envelope (Residential)	15% in 2025	15% in 2025	15% in 2017	15% in 2017
Efficiency program activity category	startup	startup	active	active

Source: U.S. Energy Information Administration.

Appendix G

Table 27. Summary results for AEO2015 Reference case and Clean Power Plan cases, selected years

	2005	2013	2020										
			AEO	CPP	CPPEXT	CPPNUC	CPPEENO	CPPEEHI	CPP BIO195	CPPTSD	CPPEOR	CPPUS	CPP LIMTR
ELECTRIC GENERATION (billion kWh)													
Coal	2,013	1,586	1,709	1,340	1,324	1,357	1,336	1,341	1,313	1,148	1,329	1,449	1,303
Natural Gas	761	1,118	1,117	1,382	1,359	1,371	1,364	1,371	1,420	1,561	1,395	1,252	1,386
Nuclear	782	789	804	804	804	804	804	804	804	804	804	804	804
Hydro	270	267	292	295	296	295	297	295	296	295	295	296	295
Wind	18	168	232	272	313	269	291	268	272	266	270	316	290
Solar	1	19	51	60	60	60	70	60	62	59	59	54	60
Other renewables	69	76	104	114	112	114	119	115	96	113	113	110	124
Oil/ other	142	47	43	41	41	41	41	41	41	40	41	42	41
Total	4,055	4,070	4,351	4,308	4,308	4,311	4,322	4,294	4,305	4,287	4,307	4,322	4,305
ELECTRIC GENERATION CAPACITY (GW)													
Coal	313	304	263	217	210	222	218	216	215	213	217	225	217
Natural gas / Oil	442	470	482	490	491	490	493	490	491	496	490	491	490
Nuclear	100	99	101	101	101	101	101	101	101	101	101	101	101
Hydro	78	79	80	80	80	80	80	80	80	80	80	80	80
Wind	9	61	83	100	114	99	106	98	100	98	99	114	106
Solar	0	13	28	32	32	32	37	32	34	32	32	29	33
Other renewables	12	15	17	18	18	18	19	18	17	18	18	18	20
Other	24	25	26	26	26	26	26	26	26	26	26	26	26
Total	978	1,065	1,079	1,065	1,074	1,068	1,081	1,062	1,063	1,065	1,064	1,084	1,072
ELECTRICITY-RELATED CARBON DIOXIDE EMISSIONS (million metric tons)													
Power sector	2,416	2,053	2,107	1,814	1,794	1,825	1,803	1,810	1,801	1,684	1,818	1,870	1,779
ELECTRICITY PRICES (2013 cents per kWh)													
Residential	11.0	12.2	12.9	13.5	13.5	13.4	13.3	13.7	13.5	13.8	13.5	13.2	13.5
Commercial	10.1	10.1	10.6	11.1	11.1	11.1	11.0	11.3	11.2	11.5	11.2	10.9	11.2
Industrial	6.6	6.9	7.3	7.7	7.7	7.7	7.6	7.9	7.8	8.0	7.8	7.5	7.7
All Sectors[1]	9.4	10.1	10.5	11.0	11.0	11.0	10.9	11.2	11.1	11.4	11.1	10.8	11.1
ELECTRICITY EXPENDITURES (billion 2013 dollars)													
Residential	149.0	169.2	183.6	189.8	189.8	189.2	188.6	192.2	190.7	194.3	190.4	186.9	190.1
Commercial	128.2	135.7	150.1	155.9	156.1	155.4	154.6	157.8	156.9	160.3	156.5	153.0	156.4
Industrial	67.8	65.8	79.6	83.3	83.1	82.8	82.2	84.6	83.7	85.7	83.7	81.3	83.2
Total[2]	345.0	370.7	413.3	429.1	429.0	427.4	425.4	434.7	431.3	440.3	430.6	421.1	429.7
ENERGY PRODUCTION (quadrillion Btu)													
Natural Gas	18.6	25.1	29.6	30.9	30.7	30.8	30.7	30.8	30.9	31.7	30.9	30.2	30.8
Coal	23.2	20.0	21.7	17.6	17.4	17.7	17.5	17.6	17.3	15.5	17.4	18.7	17.2
Oil	13.3	19.2	27.7	27.7	27.7	27.7	27.7	27.7	27.7	27.7	27.7	27.7	27.7
Nuclear	8.2	8.3	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Renewable	6.2	9.0	10.4	11.0	11.4	11.0	11.4	11.0	10.8	11.0	11.0	11.4	11.4
Other	0.0	1.3	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.8	0.9	0.9	0.9
Total	69.4	82.7	98.7	96.5	96.5	96.5	96.7	96.4	96.0	95.1	96.3	97.3	96.3

Table 27. Summary results for AEO2015 Reference case and Clean Power Plan cases, selected years (cont.)

	2005	2013	2020										
			AEO	CPP	CPPEXT	CPPNUC	CPPEENO	CPPEEHI	BIO195	CPPTSD	CPPEOR	CPPUS	LIMTR
OTHER PRICES (2013 $/MMBtu, unless otherwise noted)													
Natural Gas (Henry Hub)	10.08	3.73	4.88	5.83	5.78	5.80	5.80	5.75	5.82	6.52	5.86	5.36	5.74
Average Delivered Natural Gas Price to Electric Power Sector	9.55	4.40	5.39	6.47	6.36	6.41	6.37	6.40	6.52	7.21	6.54	5.84	6.35
Steam Coal Minemouth Price (2013$/short ton)	24.79	31.31	32.64	32.75	32.80	32.82	32.86	32.71	32.98	33.60	32.88	32.74	32.60
Steam Coal Price Delivered to Electric Power Sector	1.79	2.34	2.38	2.29	2.29	2.30	2.29	2.30	2.29	2.27	2.30	2.33	2.28
Brent Spot Price (2013 dollars per barrel)	63.32	108.64	79.13	79.09	79.10	79.09	79.10	79.10	79.11	79.01	79.08	79.10	79.13
ECONOMIC INDICATORS (billion 2009 chain-weighted dollars, unless otherwise noted)													
Gross domestic product	14,234	15,710	18,801	18,739	18,732	18,744	18,735	18,736	18,731	18,708	18,738	18,754	18,731
Total industrial shipments	7,464	7,004	8,467	8,423	8,417	8,426	8,420	8,421	8,416	8,403	8,422	8,433	8,414
Non-farm employment (millions)	134	136	149	149	149	149	149	149	149	149	149	149	149
Average Annual Change in CPI from 2013 (%)	-	0.00%	1.75%	1.82%	1.83%	1.81%	1.82%	1.82%	1.82%	1.84%	1.82%	1.81%	1.84%
END-USE ENERGY CONSUMPTION (quadrillion Btu)													
Liquids	39.1	35.6	36.9	36.7	36.7	36.7	36.7	36.7	36.7	36.7	36.8	36.8	36.7
Natural Gas	16.6	18.5	19.0	18.9	18.9	18.9	18.9	18.9	18.9	18.7	18.8	19.0	18.9
Electricity	12.5	12.6	13.4	13.3	13.3	13.3	13.4	13.3	13.3	13.3	13.3	13.3	13.3
Coal	2.1	1.5	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
PRIMARY ENERGY (quadrillion Btu)													
Consumption	100.2	97.1	100.8	99.0	99.0	99.0	99.1	98.9	98.7	97.9	98.9	99.6	98.9
Imports	34.7	24.5	20.2	20.2	20.1	20.2	20.1	20.1	20.1	20.2	20.2	20.1	20.1
Exports	4.5	11.7	18.1	17.7	17.7	17.8	17.7	17.7	17.5	17.4	17.7	17.9	17.5
Production	69.4	82.7	98.7	96.5	96.5	96.5	96.7	96.4	96.0	95.1	96.3	97.3	96.3

Table 27. Summary results for AEO2015 Reference case and Clean Power Plan cases, selected years (cont.)

	2005	2013	2030										
			AEO	CPP	CPPEXT	CPPNUC	CPPEENO	CPPEEHI	CPP BIO195	CPPTSD	CPPEOR	CPPUS	CPP LIMTR
ELECTRIC GENERATION (billion kWh)													
Coal	2,013	1,586	1,713	1,153	1,101	1,165	1,135	1,162	1,138	1,164	1,131	1,226	1,108
Natural Gas	761	1,118	1,371	1,429	1,464	1,401	1,446	1,386	1,436	1,399	1,431	1,326	1,458
Nuclear	782	789	808	808	808	900	808	808	808	808	808	808	808
Hydro	270	267	295	299	298	298	299	297	299	299	299	299	298
Wind	18	168	245	562	575	548	585	529	571	555	571	656	556
Solar	1	19	71	148	151	96	177	144	171	162	156	98	162
Other renewables	69	76	146	146	148	138	154	145	119	151	149	143	159
Oil/other	142	47	43	40	40	40	40	40	40	40	40	40	40
Total	4,055	4,070	4,691	4,584	4,586	4,586	4,643	4,510	4,580	4,577	4,585	4,596	4,588
ELECTRIC GENERATION CAPACITY (GW)													
Coal	313	304	260	209	200	214	208	209	206	207	207	221	211
Natural gas / Oil	442	470	519	518	528	521	523	507	519	515	518	521	518
Nuclear	100	99	102	101	101	113	101	101	101	101	101	101	101
Hydro	78	79	80	81	81	81	81	80	81	81	81	81	81
Wind	9	61	87	192	198	188	200	182	195	191	196	218	190
Solar	0	13	39	76	77	51	89	73	86	82	80	52	82
Other renewables	12	15	20	23	23	22	25	23	20	24	23	22	25
Other	24	25	26	26	26	26	26	26	26	26	26	26	26
Total	978	1,065	1,133	1,226	1,235	1,215	1,253	1,202	1,235	1,226	1,231	1,242	1,234
ELECTRICITY-RELATED CARBON DIOXIDE EMISSIONS (million metric tons)													
Power sector	2,416	2,053	2,177	1,596	1,553	1,598	1,586	1,589	1,584	1,595	1,595	1,619	1,554
ELECTRICITY PRICES (2013 cents per kWh)													
Residential	11.0	12.2	13.6	14.2	14.2	14.2	14.0	14.5	14.3	14.3	14.2	14.1	14.2
Commercial	10.1	10.1	11.1	11.5	11.5	11.5	11.4	11.8	11.6	11.6	11.5	11.4	11.5
Industrial	6.6	6.9	7.7	8.0	8.1	8.0	8.0	8.1	8.1	8.1	8.0	8.0	8.0
All Sectors[1]	9.4	10.1	11.1	11.5	11.5	11.5	11.4	11.7	11.5	11.6	11.5	11.4	11.5
ELECTRICITY EXPENDITURES (billion 2013 dollars)													
Residential	149.0	169.2	202.9	205.8	205.9	205.7	206.5	206.6	206.3	206.8	205.5	204.6	205.7
Commercial	128.2	135.7	169.2	170.9	170.8	170.7	171.7	169.6	171.4	172.0	170.6	170.0	170.7
Industrial	67.8	65.8	91.2	92.7	92.9	92.6	92.2	93.5	93.1	93.2	92.6	92.5	92.4
Total[2]	345.0	370.7	463.3	469.4	469.5	469.0	470.4	469.8	470.8	472.0	468.6	467.0	468.8
ENERGY PRODUCTION (quadrillion Btu)													
Natural Gas	18.6	25.1	33.9	33.6	33.5	33.5	33.5	33.4	33.7	33.0	33.4	33.1	33.8
Coal	23.2	20.0	22.5	16.6	16.1	16.7	16.4	16.7	16.4	16.6	16.3	17.3	16.1
Oil	13.3	19.2	26.8	26.8	26.8	26.7	26.8	26.7	26.8	26.6	26.7	26.7	26.8
Nuclear	8.2	8.3	8.5	8.5	8.5	9.4	8.5	8.5	8.5	8.5	8.5	8.5	8.5
Renewable	6.2	9.0	11.0	14.8	15.0	14.1	15.4	14.4	14.7	15.0	15.0	15.1	15.1
Other	0.0	1.3	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Total	69.4	82.7	103.7	101.2	100.7	101.4	101.5	100.6	101.0	100.5	100.8	101.5	101.2

Table 27. Summary results for AEO2015 Reference case and Clean Power Plan cases, selected years (cont.)

	2005	2013	2030										
			AEO	CPP	CPPEXT	CPPNUC	CPPEENO	CPPEEHI	CPP BIO195	CPPTSD	CPPEOR	CPPUS	CPP LIMTR
OTHER PRICES (2013 $/MMBtu unless otherwise noted)													
Natural Gas (Henry Hub)	10.08	3.73	5.69	5.86	5.90	5.82	5.79	5.84	5.88	6.03	5.75	5.63	5.97
Average Delivered Natural Gas Price to Electric Power Sector	9.55	4.40	6.22	6.38	6.41	6.29	6.34	6.33	6.38	6.53	6.28	6.24	6.47
Steam Coal Minemouth Price (2013$/short ton)	24.79	31.31	36.49	32.78	33.65	32.77	32.93	32.94	32.70	33.22	32.98	34.19	32.79
Steam Coal Price Delivered to Electric Power Sector	1.79	2.34	2.67	2.33	2.32	2.32	2.32	2.33	2.31	2.35	2.32	2.43	2.31
Brent Spot Price (2013 dollars per barrel)	63.32	108.64	105.64	105.64	105.64	105.64	105.64	105.64	105.64	105.64	105.64	105.64	105.64
ECONOMIC INDICATORS (billion 2009 chain-weighted dollars, unless otherwise noted)													
Gross domestic product	14,234	15,710	23,894	23,866	23,855	23,862	23,861	23,870	23,875	23,855	23,863	23,860	23,863
Total industrial shipments	7,464	7,004	9,870	9,810	9,801	9,810	9,804	9,810	9,817	9,798	9,808	9,811	9,802
Non-farm employment (millions)	134	136	159	159	159	159	159	159	159	159	159	158	159
Average Annual Change in CPI from 2013 (%)	-	0.00%	1.85%	1.88%	1.88%	1.88%	1.88%	1.88%	1.87%	1.89%	1.88%	1.88%	1.88%
END-USE ENERGY CONSUMPTION (quadrillion Btu)													
Liquids	39.1	35.6	36.3	36.0	36.0	36.1	36.0	36.1	36.0	36.1	36.0	36.1	36.0
Natural Gas	16.6	18.5	19.8	19.7	19.6	19.7	19.6	19.7	19.7	19.5	19.6	19.7	19.6
Electricity	12.5	12.6	14.3	14.0	14.0	14.0	14.2	13.7	14.0	14.0	14.0	14.0	14.0
Coal	2.1	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
PRIMARY ENERGY (quadrillion Btu)													
Consumption	100.2	97.1	102.9	100.4	100.2	100.6	101.0	99.9	100.2	100.2	100.3	100.8	100.3
Imports	34.7	24.5	21.7	21.3	21.3	21.3	21.3	21.3	21.3	21.4	21.4	21.4	21.2
Exports	4.5	11.7	22.4	21.9	21.7	21.9	21.7	21.9	21.9	21.5	21.7	21.9	22.0
Production	69.4	82.7	103.7	101.2	100.7	101.4	101.5	100.6	101.0	100.5	100.8	101.5	101.2

Table 27. Summary results for AEO2015 Reference case and Clean Power Plan cases, selected years (cont.)

	2005	2013	2040										
			AEO	CPP	CPPEXT	CPPNUC	CPPEENO	CPPEEHI	CPP BIO195	CPPTSD	CPPEOR	CPPUS	CPP LIMTR
ELECTRIC GENERATION (billion kWh)													
Coal	2,013	1,586	1,702	1,278	904	1,306	1,274	1,289	1,258	1,298	1,256	1,373	1,235
Natural Gas	761	1,118	1,569	1,456	1,560	1,400	1,465	1,408	1,447	1,400	1,458	1,340	1,496
Nuclear	782	789	833	813	811	962	816	808	819	814	812	809	814
Hydro	270	267	297	300	301	299	300	299	300	299	300	301	300
Wind	18	168	319	602	812	604	638	567	611	596	606	710	582
Solar	1	19	110	275	292	171	321	254	310	299	288	222	287
Other renewables	69	76	183	178	184	166	179	174	150	176	177	168	187
Oil/other	142	47	43	41	39	41	41	41	41	41	41	41	41
Total	4,055	4,070	5,056	4,942	4,903	4,948	5,034	4,839	4,935	4,924	4,938	4,964	4,941
ELECTRIC GENERATION CAPACITY (GW)													
Coal	313	304	260	209	197	214	208	209	206	207	207	221	211
Natural gas / Oil	442	470	595	579	582	578	586	562	577	572	576	584	576
Nuclear	100	99	105	102	102	121	102	101	103	102	102	102	102
Hydro	78	79	80	81	81	81	81	81	81	81	81	81	81
Wind	9	61	110	205	273	206	218	195	208	205	207	235	198
Solar	0	13	61	136	146	87	157	128	153	146	142	112	142
Other renewables	12	15	24	26	28	25	27	26	22	26	26	25	28
Other	24	25	26	26	26	26	26	26	26	26	26	26	26
Total	978	1,065	1,261	1,365	1,435	1,337	1,405	1,327	1,376	1,365	1,367	1,385	1,365
ELECTRICITY-RELATED CARBON DIOXIDE EMISSIONS (million metric tons)													
Power sector	2,416	2,053	2,195	1,691	1,329	1,696	1,690	1,682	1,667	1,686	1,689	1,733	1,653
ELECTRICITY PRICES (2013 cents per kWh)													
Residential	11.0	12.2	14.5	14.9	15.3	14.8	14.7	15.1	14.9	15.0	14.9	14.6	14.9
Commercial	10.1	10.1	11.8	12.1	12.5	12.1	11.9	12.4	12.2	12.3	12.2	11.9	12.2
Industrial	6.6	6.9	8.4	8.6	9.0	8.5	8.5	8.7	8.6	8.7	8.6	8.4	8.6
All Sectors[1]	9.4	10.1	11.8	12.1	12.5	12.1	12.0	12.3	12.2	12.3	12.2	11.9	12.2
ELECTRICITY EXPENDITURES (billion 2013 dollars)													
Residential	149.0	169.2	229.9	230.6	235.0	229.7	231.9	231.0	231.3	232.3	231.2	227.7	231.3
Commercial	128.2	135.7	195.4	192.8	196.7	192.1	196.8	187.9	193.2	194.6	193.3	190.1	193.8
Industrial	67.8	65.8	101.5	101.7	105.3	101.3	101.2	102.0	102.2	102.9	102.1	100.0	101.7
Total[2]	345.0	370.7	526.7	525.1	537.0	523.1	529.9	520.9	526.8	529.9	526.6	517.7	526.8
ENERGY PRODUCTION (quadrillion Btu)													
Natural Gas	18.6	25.1	36.4	35.0	35.2	34.8	34.9	34.8	34.9	34.1	34.8	34.6	35.3
Coal	23.2	20.0	22.6	18.3	14.6	18.6	18.3	18.4	18.1	18.4	18.0	19.1	17.8
Oil	13.3	19.2	25.4	25.4	25.5	25.4	25.3	25.3	25.4	25.4	25.3	25.1	25.5
Nuclear	8.2	8.3	8.7	8.5	8.5	10.1	8.5	8.5	8.6	8.5	8.5	8.5	8.5
Renewable	6.2	9.0	12.5	16.7	18.9	15.5	17.5	16.1	16.7	16.8	16.9	17.0	16.8
Other	0.0	1.3	1.0	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	1.0	0.9
Total	69.4	82.7	106.6	104.9	103.6	105.4	105.6	104.0	104.6	104.2	104.4	105.3	104.8

Table 27. Summary results for AEO2015 Reference case and Clean Power Plan cases, selected years (cont.)

	2005	2013	2040										
			AEO	CPP	CPPEXT	CPPNUC	CPPEENO	CPPEEHI	CPP BIO195	CPPTSD	CPPEOR	CPPUS	CPP LIMTR
OTHER PRICES (2013 $/MMBtu unless otherwise noted)													
Natural Gas (Henry Hub)	10.08	3.73	7.85	8.15	8.12	8.11	8.00	7.99	8.26	8.49	8.15	7.64	8.17
Average Delivered Natural Gas Price to Electric Power Sector	9.55	4.40	8.28	8.32	8.33	8.13	8.20	8.13	8.46	8.59	8.29	7.82	8.39
Steam Coal Minemouth Price (2013$/short ton)	24.79	31.31	40.94	37.48	36.06	37.51	37.51	37.51	36.96	37.63	37.39	38.29	37.28
Steam Coal price Delivered to Electric Power Sector	1.79	2.34	2.92	2.61	2.41	2.63	2.62	2.63	2.59	2.63	2.61	2.71	2.60
Brent Spot Price (2013 dollars per barrel)	63.32	108.64	141.98	141.98	141.98	141.98	141.98	141.98	141.98	141.98	141.98	141.98	141.98
ECONOMIC INDICATORS (billion 2009 chain-weighted dollars, unless otherwise noted)													
Gross domestic product	14,234	15,710	29,898	29,886	29,831	29,899	29,901	29,861	29,881	29,897	29,879	29,903	29,881
Total industrial shipments	7,464	7,004	11,463	11,418	11,374	11,423	11,424	11,398	11,416	11,413	11,413	11,420	11,415
Non-farm employment (millions)	134	136	169	169	169	169	169	169	169	169	169	169	169
Average Annual Change in CPI from 2013 (%)	-	0.00%	1.98%	1.99%	2.00%	1.99%	1.99%	2.00%	1.99%	2.00%	1.99%	1.99%	1.99%
END-USE ENERGY CONSUMPTION (quadrillion Btu)													
Liquids	39.1	35.6	36.0	35.9	35.8	35.9	35.9	35.9	35.9	35.9	35.9	35.9	35.9
Natural Gas	16.6	18.5	20.9	20.7	20.7	20.8	20.7	20.8	20.7	20.5	20.7	20.9	20.7
Electricity	12.5	12.6	15.3	14.8	14.7	14.8	15.1	14.5	14.8	14.8	14.8	14.9	14.8
Coal	2.1	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
PRIMARY ENERGY (quadrillion Btu)													
Consumption	100.2	97.1	105.7	104.0	102.7	104.4	104.9	103.1	103.7	103.7	103.8	104.6	103.9
Imports	34.7	24.5	24.1	23.7	23.5	23.7	23.8	23.7	23.7	23.7	23.7	23.8	23.7
Exports	4.5	11.7	24.6	24.3	24.1	24.4	24.1	24.3	24.2	23.9	24.0	24.2	24.3
Production	69.4	82.7	106.6	104.9	103.6	105.4	105.6	104.0	104.6	104.2	104.4	105.3	104.8

[1]All sector average price includes transportation sector.
[2]Total expenditures exclude transportation sector.

Source: U.S. Energy Information Administration.

Appendix H

Table 28. Summary results for AEO2015 High Oil and Gas Resource, High Economic Growth and CPP cases, selected years

	2005	2013	2020				2030				2040			
			AEO HOGR	CPP HOGR	AEO HEG	CPP HEG	AEO HOGR	CPP HOGR	AEO HEG	CPP HEG	AEO HOGR	CPP HOGR	AEO HEG	CPP HEG
ELECTRIC GENERATION (billion kWh)														
Coal	2,013	1,586	1,443	1,212	1,733	1,415	1,441	898	1,733	1,293	1,440	910	1,744	1,421
Natural Gas	761	1,118	1,450	1,610	1,204	1,377	1,832	2,092	1,573	1,422	2,200	2,439	1,705	1,475
Nuclear	782	789	804	804	804	804	808	808	818	808	808	808	911	863
Hydro	270	267	289	294	294	305	290	295	297	305	290	295	298	308
Wind	18	168	229	263	243	315	232	407	301	634	234	412	489	725
Solar	1	19	51	59	52	70	65	85	80	247	85	106	160	420
Other renewables	69	76	107	110	106	117	146	128	158	161	175	145	222	207
Oil/other	142	47	44	41	43	42	42	39	43	41	42	40	43	42
Total	4,055	4,070	4,417	4,392	4,480	4,445	4,854	4,753	5,003	4,912	5,274	5,154	5,574	5,461
ELECTRIC GENERATION CAPACITY (GW)														
Coal	313	304	245	201	265	230	242	173	263	223	242	173	264	223
Natural gas / Oil	442	470	497	516	490	497	573	607	564	540	674	704	657	629
Nuclear	100	99	101	101	101	101	101	101	103	102	101	101	115	109
Hydro	78	79	79	80	80	82	79	80	80	82	79	80	81	83
Wind	9	61	82	97	87	115	83	142	105	216	84	144	165	245
Solar	0	13	27	32	28	38	36	45	44	121	48	58	82	200
Other renewables	12	15	17	18	18	19	20	21	23	26	22	23	32	31
Other	24	25	26	26	26	26	26	26	26	26	26	26	26	26
Total	978	1,065	1,075	1,070	1,094	1,108	1,159	1,196	1,207	1,335	1,275	1,309	1,422	1,546
ELECTRICITY-RELATED CARBON DIOXIDE EMISSIONS (million metric tons)														
Power sector	2,416	2,053	1,973	1,789	2,165	1,886	2,089	1,605	2,262	1,727	2,179	1,701	2,266	1,827
ELECTRICITY PRICES (2013 cents per kWh)														
Residential	11.0	12.2	12.3	12.6	12.9	13.4	12.6	13.1	13.7	14.1	12.8	13.1	14.9	15.1
Commercial	10.1	10.1	10.1	10.3	10.8	11.1	10.0	10.4	11.3	11.6	10.2	10.4	12.4	12.6
Industrial	6.6	6.9	6.8	7.0	7.4	7.7	6.8	7.1	7.9	8.1	7.1	7.2	8.9	8.9
All Sectors[1]	9.4	10.1	10.0	10.2	10.6	10.9	10.0	10.4	11.1	11.5	10.3	10.5	12.3	12.4
ELECTRICITY EXPENDITURES (billion 2013 dollars)														
Residential	149	169	177	179	190	194	192	194	220	222	211	211	265	264
Commercial	128	136	144	146	153	156	156	158	174	175	174	172	209	205
Industrial	68	66	76	78	86	89	86	88	104	105	90	91	127	126
Total[2]	345	371	397	403	428	439	434	440	498	502	475	473	602	594
ENERGY PRODUCTION (quadrillion Btu)														
Natural Gas	18.6	25.1	33.1	34.0	30.0	30.8	43.8	45.0	35.3	33.9	52.0	52.2	37.7	36.0
Coal	23.2	20.0	18.8	16.3	22.0	18.4	19.8	14.0	23.0	18.3	20.3	14.7	23.5	20.0
Oil	13.3	19.2	32.6	32.6	27.7	27.7	40.5	40.5	27.1	27.0	43.6	43.3	26.0	25.8
Nuclear	8.2	8.3	8.4	8.4	8.4	8.4	8.5	8.5	8.6	8.5	8.5	8.5	9.5	9.0
Renewable	6.2	9.0	10.4	10.9	10.7	11.8	10.9	12.6	12.0	16.9	11.4	13.0	15.5	20.1
Other	0.0	1.3	0.9	0.9	0.9	0.9	1.0	1.0	1.0	0.9	1.0	1.0	1.0	1.0
Total	69.4	82.7	104.3	103.1	99.7	98.1	124.4	121.6	107.0	105.6	136.8	132.7	113.3	111.9

Table 28. Summary results for AEO2015 High Oil and Gas Resource, High Economic Growth and CPP cases, selected years (cont.)

	2005	2013	2020				2030				2040			
			AEO HOGR	CPP HOGR	AEO HEG	CPP HEG	AEO HOGR	CPP HOGR	AEO HEG	CPP HEG	AEO HOGR	CPP HOGR	AEO HEG	CPP HEG
OTHER PRICES (2013 $/MMBtu unless otherwise noted)														
Natural Gas (Henry Hub)	10.08	3.73	3.12	3.38	5.03	5.75	3.67	3.81	6.02	5.81	4.38	4.47	8.45	8.49
Average Delivered Natural Gas Price to Electric Power Sector	9.55	4.40	3.68	4.07	5.65	6.34	4.15	4.27	6.61	6.31	4.67	4.86	8.71	8.57
Steam Coal Minemouth Price (2013$/short ton)	24.79	31.31	31.18	31.37	32.74	33.37	33.82	31.32	36.61	33.83	37.96	34.78	41.60	38.92
Steam Coal price Delivered to Electric Power Sector	1.79	2.34	2.24	2.18	2.39	2.33	2.44	2.12	2.68	2.41	2.67	2.30	2.96	2.73
Oil price (2013 dollars per barrel)	63.32	108.64	75.72	75.40	79.67	79.62	98.15	97.99	107.51	107.24	129.38	129.52	145.17	144.91
ECONOMIC INDICATORS (billion 2009 chain-weighted dollars, unless otherwise noted)														
Gross domestic product	14,234	15,710	18,841	18,796	19,590	19,526	24,222	24,192	26,146	26,126	30,236	30,186	34,146	34,107
Total industrial shipments	7,464	7,004	8,566	8,536	8,967	8,924	10,349	10,314	11,081	11,022	11,989	11,969	13,786	13,656
Non-farm employment (millions)	134	136	149	149	152	152	160	160	166	166	170	170	176	176
Average Annual Change in CPI from 2013 (%)	-	0.00%	1.56%	1.60%	1.67%	1.74%	1.63%	1.63%	1.62%	1.65%	1.85%	1.84%	1.80%	1.82%
END-USE ENERGY CONSUMPTION (quadrillion Btu)														
Liquids	39.1	35.6	37.4	37.3	37.8	37.6	37.7	37.4	38.3	38.2	37.4	37.3	39.7	39.4
Natural Gas	16.6	18.5	19.8	19.7	19.2	19.1	21.9	21.9	20.6	20.6	24.1	24.0	22.5	22.4
Electricity	12.5	12.6	13.6	13.6	13.8	13.7	14.8	14.5	15.3	15.0	15.9	15.5	16.8	16.4
Coal	2.1	1.5	1.6	1.6	1.7	1.7	1.6	1.5	1.8	1.8	1.5	1.5	1.9	1.9
PRIMARY ENERGY (quadrillion Btu)														
Consumption	100.2	97.1	101.8	100.6	103.1	101.6	106.8	103.7	108.5	107.2	110.8	107.7	116.2	114.9
Imports	34.7	24.5	19.9	20.4	21.0	20.9	18.2	18.0	23.5	23.2	18.3	18.4	27.3	26.9
Exports	4.5	11.7	22.5	23.0	17.7	17.4	35.7	35.8	21.7	21.4	44.0	43.2	23.9	23.5
Production	69.4	82.7	104.3	103.1	99.7	98.1	124.4	121.6	107.0	105.6	136.8	132.7	113.3	111.9

[1]All sector average price includes transportation sector.

[2]Total expenditures exclude transportation sector.

Source: U.S. Energy Information Administration.

Appendix I

Table 29. Summary results for Heat Rate sensitivity reference and Clean Power Plan cases, selected years

	2005	2013	2020				2030				2040			
			AEO HRILO	CPP HRILO	AEO HRIHI	CPP HRIHI	AEO HRILO	CPP HRILO	AEO HRIHI	CPP HRIHI	AEO HRILO	CPP HRILO	AEO HRIHI	CPP HRIHI
ELECTRIC GENERATION (billion kWh)														
Coal	2,013	1,586	1,709	1,336	1,709	1,341	1,709	1,137	1,710	1,154	1,700	1,271	1,701	1,289
Natural Gas	761	1,118	1,117	1,390	1,117	1,381	1,380	1,421	1,376	1,418	1,569	1,436	1,568	1,433
Nuclear	782	789	804	804	804	804	809	809	810	808	830	818	831	812
Hydro	270	267	292	295	292	295	295	298	295	299	297	299	297	300
Wind	18	168	231	269	232	271	246	579	244	559	317	619	317	604
Solar	1	19	51	59	51	60	71	152	70	162	110	282	109	290
Other renewables	69	76	104	112	105	114	145	148	145	146	187	176	187	176
Oil/other	142	47	43	41	43	41	43	40	43	40	43	41	43	41
Total	4,055	4,070	4,350	4,307	4,352	4,307	4,697	4,583	4,692	4,585	5,053	4,941	5,053	4,945
ELECTRIC GENERATION CAPACITY (GW)														
Coal	313	304	263	218	263	217	260	208	260	209	260	208	260	209
Natural gas / Oil	442	470	481	489	482	490	518	517	518	515	592	577	594	577
Nuclear	100	99	101	101	101	101	102	102	102	101	104	103	105	102
Hydro	78	79	80	80	80	80	80	81	80	81	80	81	80	81
Wind	9	61	83	99	83	99	88	198	87	192	109	211	109	206
Solar	0	13	28	32	28	33	39	77	39	82	61	139	60	143
Other renewables	12	15	17	18	17	18	20	24	20	23	25	26	25	26
Other	24	25	26	26	26	26	26	26	26	26	26	26	26	26
Total	978	1,065	1,078	1,064	1,078	1,065	1,133	1,232	1,132	1,229	1,258	1,371	1,260	1,370
ELECTRICITY-RELATED CARBON DIOXIDE EMISSIONS (million metric tons)														
Power sector	2,416	2,053	2,109	1,826	2,109	1,810	2,181	1,597	2,176	1,595	2,199	1,692	2,191	1,691
ELECTRICITY PRICES (2013 cents per kWh)														
Residential	11.0	12.2	12.9	13.5	12.9	13.5	13.6	14.2	13.6	14.2	14.5	14.9	14.5	14.8
Commercial	10.1	10.1	10.7	11.2	10.6	11.1	11.0	11.5	11.1	11.5	11.8	12.1	11.8	12.1
Industrial	6.6	6.9	7.3	7.8	7.3	7.7	7.7	8.0	7.7	8.0	8.5	8.6	8.5	8.6
All Sectors[1]	9.4	10.1	10.5	11.1	10.5	11.0	11.0	11.5	11.0	11.5	11.9	12.1	11.9	12.1
ELECTRICITY EXPENDITURES (billion 2013 dollars)														
Residential	149	169	184	190	184	190	202	206	202	206	230	230	231	230
Commercial	128	136	150	156	150	156	168	171	169	171	196	193	196	192
Industrial	68	66	80	84	80	83	91	93	91	93	102	102	102	102
Total[2]	345	371	414	430	414	430	461	469	462	469	528	525	529	524
ENERGY PRODUCTION (quadrillion Btu)														
Natural Gas	18.6	25.1	29.6	30.9	29.6	30.9	34.0	33.6	33.9	33.6	36.4	34.9	36.4	34.9
Coal	23.2	20.0	21.7	17.6	21.7	17.5	22.5	16.5	22.5	16.5	22.7	18.4	22.6	18.4
Oil	13.3	19.2	27.7	27.7	27.7	27.7	26.8	26.7	26.8	26.8	25.3	25.4	25.6	25.4
Nuclear	8.2	8.3	8.4	8.4	8.4	8.4	8.5	8.5	8.5	8.5	8.7	8.6	8.7	8.5
Renewable	6.2	9.0	10.4	11.0	10.4	11.0	11.0	15.1	11.0	14.9	12.5	16.9	12.5	16.8
Other	0.0	1.3	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	1.0	0.9	1.0	0.9
Total	69.4	82.7	98.7	96.5	98.7	96.4	103.7	101.3	103.7	101.1	106.5	105.2	106.8	105.0

Table 29. Summary results for Heat Rate sensitivity reference and Clean Power Plan cases, selected years (cont.)

	2005	2013	2020				2030				2040			
			AEO HRILO	CPP HRILO	AEO HRIHI	CPP HRIHI	AEO HRILO	CPP HRILO	AEO HRIHI	CPP HRIHI	AEO HRILO	CPP HRILO	AEO HRIHI	CPP HRIHI
OTHER PRICES (2013 $/MMBtu unless otherwise noted)														
Natural Gas (Henry Hub)	10.08	3.73	4.89	5.80	4.94	5.84	5.75	5.80	5.78	5.84	7.93	8.13	7.84	8.11
Average Delivered Natural Gas Price to Electric Power Sector	9.55	4.40	5.39	6.46	5.38	6.48	6.27	6.34	6.37	6.35	8.31	8.29	8.17	8.26
Steam Coal Minemouth Price (2013$/short-ton)	24.79	31.31	32.72	32.88	32.74	33.05	36.39	32.92	36.39	32.81	40.93	37.36	40.92	37.54
Steam Coal price Delivered to Electric Power Sector	1.79	2.34	2.38	2.30	2.39	2.30	2.67	2.31	2.67	2.32	2.92	2.60	2.92	2.61
Brent Spot Price (2013 dollars per barrel)	63.32	108.64	79.10	79.09	79.11	79.09	105.64	105.64	105.64	105.64	141.30	141.32	141.27	141.31
ECONOMIC INDICATORS (billion 2009 chain-weighted dollars, unless otherwise noted)														
Gross domestic product	14,234	15,710	18,801	18,740	18,801	18,739	23,895	23,859	23,898	23,860	29,882	29,895	29,884	29,890
Total industrial shipments	7,464	7,004	8,467	8,424	8,467	8,423	9,871	9,803	9,872	9,806	11,454	11,417	11,454	11,417
Non-farm employment (millions)	134	136	149	149	149	149	159	159	159	159	168	169	168	169
Average Annual Change in CPI from 2013 (%)	-	0.00%	1.75%	1.82%	1.75%	1.82%	1.85%	1.88%	1.85%	1.88%	1.98%	1.99%	1.98%	1.99%
END-USE ENERGY CONSUMPTION (quadrillion Btu)														
Liquids	39.1	35.6	36.9	36.7	36.9	36.7	36.3	36.0	36.3	36.0	36.0	35.9	36.0	35.9
Natural Gas	16.6	18.5	19.0	18.9	19.0	18.9	19.8	19.6	19.8	19.6	20.9	20.7	20.9	20.7
Electricity	12.5	12.6	13.4	13.3	13.4	13.3	14.4	14.0	14.4	14.0	15.2	14.8	15.2	14.8
Coal	2.1	1.5	1.6	1.6	1.6	1.6	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
PRIMARY ENERGY (quadrillion Btu)														
Consumption	100.2	97.1	100.9	99.1	100.9	98.9	102.9	100.5	102.8	100.4	105.8	104.2	105.7	104.1
Imports	34.7	24.5	20.3	20.2	20.3	20.2	21.7	21.3	21.7	21.3	24.2	23.6	23.9	23.7
Exports	4.5	11.7	18.1	17.7	18.1	17.7	22.4	21.9	22.4	21.9	24.6	24.3	24.6	24.3
Production	69.4	82.7	98.7	96.5	98.7	96.4	103.7	101.3	103.7	101.1	106.5	105.2	106.8	105.0

[1]All sector average price includes transportation sector.

[2]Total expenditures exclude transportation sector.

Source: U.S. Energy Information Administration