September 2011

Potential Impacts of EPA Air, Coal Combustion Residuals, and Cooling Water Regulations

Prepared for:

American Coalition for Clean Coal Electricity

Prepared by:

NERA

Economic Consulting

Project Team

David Harrison, Jr., Ph.D.
Andrew Foss
James Johndrow
Eugene Meehan
Bernard Reddy, Ph.D.
Anne Smith, Ph.D.

NERA Economic Consulting
200 Clarendon Street, 11th Floor
Boston, Massachusetts 02116
Tel: +1 617 927 4500
Fax: +1 617 927 4501
www.nera.com

Contents

Executive Summary

This report evaluates the potential energy and economic impacts of four major environmental regulations that would affect the electricity sector. The regulations include two major air emission policies—the Cross-State Air Pollution Rule (CSAPR) and regulation of mercury and other hazardous emissions (Utility MACT)—as well as policies to regulate coal combustion residuals (CCR) under the Resource Conservation and Recovery Act and to regulate cooling water intake under Section 316(b) of the Clean Water Act. We focus on the potential near- and medium-term (2012-2020) implications for electricity and other energy prices and for national economic impacts. This methodology is designed to complement analyses of individual regulations, including assessments of their social benefits and costs.

A. Background

Environmental legislation provides the mandate for the development of individual regulations. The U.S. Environmental Protection Agency (EPA)—sometimes in conjunction with state environmental agencies—develops regulations to implement these Congressional directives. EPA typically proposes a single regulation and provides information on its individual social costs and benefits (and other impacts), with previously-promulgated regulations being included in the baseline and the implications of other potential future regulations not considered.

In addition to analyses of individual regulations and their social costs and benefits, however, there are other impacts of environmental regulations that are of interest to policy makers but that are not necessarily included in regulatory analyses. Interest in "green jobs" has provided one additional focus. Some studies have noted that environmental mandates will increase employment in pollution control and clean technology sectors (see, e.g., Ceres 2010). Other commentators, however, have noted that these results ignore the jobs lost in the rest of the economy due to other impacts of the regulations, including increased electricity and other energy prices (see, e.g., Montgomery 2011).

There also has been a concern that focusing on individual regulations neglects the cumulative effects of multiple environmental regulations. Since these initiatives tend to increase future costs for coal-fired power plants, many studies have assessed the potential for regulations to lead to increases in coal unit retirements—since owners of some coal-fired power plants will choose to retire their units rather than install expensive control equipment—and some of these studies have assessed the possibility of impacts on electric system reliability.[1] Projections for a continuation of the recent trend of low electricity prices—driven by low natural gas prices—tend to increase pressures for coal unit retirements. Coal unit retirements and compliance costs for units that do not retire in turn can lead to increases in electricity and natural gas prices and decreases in coal prices. These changes in energy market conditions can lead to changes in output and employment.

[1] See Bipartisan Policy Center (2011), Brattle Group (2010), Charles River Associates (2010b), Edison Electric Institute (2011), ICF International (2010), M.J. Bradley & Associates and Analysis Group (2011), and North American Electric Reliability Corporation (2010).

B. Objectives and Methodology of This Study

This study develops a set of models to evaluate the potential effects of various environmental regulations on energy markets and economic activity. This methodology thus complements those that have been developed to estimate the costs and benefits—and other impacts—of individual regulations.

Specifically, this report develops estimates of the effects over the period from 2012 to 2020 of the four environmental regulations—the two air emission regulations as well as CCR and Section 316(b)—in three major areas:

1. *Coal unit retirements*. These are estimates of the effects of potential costs on future coal unit retirements. As noted, we develop a probability distribution based upon the range of uncertain parameters.

2. *Electricity and other energy market impacts*. These impacts include the potential effects on energy markets—including coal, natural gas, and electricity—as well as on overall compliance costs.

3. *Economic impacts*. These effects include impacts on the U.S. economy, including employment, gross domestic product (GDP), and disposable personal income (i.e., personal income after taxes).

The modeling framework begins with a set of detailed estimates of the likely compliance technologies—and their costs—associated with the individual regulations. These assessments are based upon the requirements of the individual regulations, including taking into account the potential flexibility provided under CSAPR.[2] For the CCR and Section 316(b) regulations, we use EPA estimates of compliance costs for the various affected units. The result is a set of estimates of the potential technologies and costs to individual electricity generating units under the four policies.

The next task is to estimate the effects of these projected costs on future retirements of coal-fired power plants. The retirement model we develop is a Monte Carlo uncertainty model designed to predict potential economic retirements based upon comparisons of the future costs of the coal-fired unit in comparison to the costs of the likely new generation that would be added in the future. The model incorporates uncertainties in key parameters affecting this comparison, including control costs and electricity and fuel (notably natural gas) prices; the model also takes account of the feedback effects of coal unit retirements on electricity and fuel prices.

The estimated coal unit retirements and the estimated compliance costs for non-retiring units are then input to the U.S. Department of Energy's National Energy Model System (NEMS) model, a well-established modeling framework used by the Energy Information Administration (EIA) to evaluate energy and environmental policies. To develop estimates of changes in employment and

---

2 The implications of the emissions trading provisions of CSAPR for technology choices at individual units are developed through an initial run of the NEMS model (a model that is described in the text).

other economic impacts, the NEMS results are input to the Policy Insight Plus model developed by Regional Economic Models, Inc. (REMI PI+), a model used extensively by numerous government agencies and private groups to assess the economic impacts of public and private policies.

Although we have attempted to develop comprehensive assessments, the results should be viewed as subject to considerable uncertainties beyond those incorporated in the analyses. Projected coal unit retirements, for example, do not include the effects of other potential regulatory requirements—notably those related to greenhouse gases—and the impacts do not include potential effects of coal unit retirements on (or constraints related to) electricity system reliability. These omitted factors could lead to additional impacts beyond those estimated in this study.

C. Results of This Study

1. Coal Unit Retirements

The potential costs of the four policies are estimated to lead to 39 gigawatts (GW) of prematurely retired capacity by 2015 among the current coal-fired power plants. This estimate represents additional retirements above those in the reference case (i.e., retirements predicted without the four regulations in place) and accounts for about 12 percent of the 2010 U.S. coal-fired electricity generating capacity.[3] As noted, this estimate does not include the potential effects of other potential requirements—notably potential greenhouse gas emission regulations—or concerns related to detailed electricity system reliability.

2. Energy Market Effects

As noted, the energy market impacts of the various regulations were estimated using the National Energy Modeling System (NEMS) based on estimates of the coal units that retire and the compliance costs for units that do not retire. The NEMS output includes estimates of overall compliance costs for the electric sector as well as detailed impacts on energy markets.

Table ES-1 summarizes the potential costs for the electricity sector based on the level of coal retirements predicted in the retirement model. These costs include compliance costs for coal units that do not retire, capital costs for new capacity that would replace retiring coal units, and changes in fuel costs. Costs are projected to be approximately $21 billion (in 2010$) per year over the period from 2012 to 2020. The costs represent a total of $127 billion (present value in 2010$ as of January 1, 2011) over the period from 2012 to 2020. Capital costs for environmental controls and replacement capacity are about $104 billion.[4]

---

[3] This level of retirements is estimated in the retirement model and is not influenced by utility retirement announcements.

[4] Capital costs exceed the total for environmental controls and replacement capacity because of net reductions in operating and maintenance costs.

Table ES-1. Electricity Sector Costs, 2012-2020 (billion 2010$)

	Annual Avg	PV
Environmental Controls	$15	$89
Replacement Capacity	$2	$11
Fuel	$5	$28
Total	$21	$127

Note: Compliance costs from 2012 through 2020 are discounted to January 1, 2011 using a real annual discount rate of 7 percent.
Annual average costs are based on the present values and discounting.
The cost of environmental controls includes net cost savings for operating and maintenance (O&M) expenses.
Source: NERA calculations as explained in text

The retirement of coal units and construction of replacement capacity affect electricity sector fuel consumption, fuel prices, and electricity prices. Table ES-2 summarizes the average potential energy market effects of the four regulations from 2012 to 2020. Appendix C provides information on the annual effects for 2012-2020, with effects that are both higher and lower than these average values.

Table ES-2. Average Annual Energy Market Impacts, 2012-2020

	Coal Retirements (GW)	Coal-Fired Generation (million MWh)	Coal Price at Minemouth (2010$/ton)	Gas-Fired Generation (million MWh)	Gas Price at Henry Hub (2010$/MMBtu)	Avg Retail Elec Price (2010$/MWh)
Average of 2012-2020 Projections						
Reference	3.1	1,911	$33.54	639	$4.48	$86.87
CSAPR+MACT+CCR+316(b)	42.2	1,699	$31.61	765	$4.95	$92.52
Change from Average of 2012-2020 Reference Projections						
CSAPR+MACT+CCR+316(b)	+39.1	-212	-$1.93	+126	+$0.48	+$5.65
% Change from Average of 2012-2020 Reference Projections						
CSAPR+MACT+CCR+316(b)	+1241%	-11.1%	-5.7%	+19.7%	+10.7%	+6.5%

Note: Coal retirements are cumulative from 2010 through 2020.
Source: NERA calculations as explained in text

Coal-fired generation is projected to decrease by an average of 11.1 percent over the period from 2012 to 2020. The reduction in coal demand is projected to decrease coal prices by 5.7 percent on average. In contrast, the regulations are predicted to increase natural gas-fired generation by 19.7 percent on average over the period and increase Henry Hub natural gas prices by 10.7 percent on average. The increases in natural gas prices would lead to an estimated average increase in costs of about $8 billion per year for residential, commercial and industrial natural gas consumers, which translates into an increase of $52 billion over the 2012-2020 period (present value in 2010$ as of 2011 discounted at 7 percent). Average U.S. retail electricity prices are projected to increase by an average of 6.5 percent over the period. Information on the annual energy market effects from 2012 to 2020 is provided in Appendix C.

3. Economic Impacts

The potential economic impacts of the four policies were estimated using the REMI PI+ model. Table ES-3 summarizes the potential economic impacts. The table shows both the average annual changes over the period from 2012 to 2020 as well as the cumulative effects over the same time period. These net figures take into account jobs that would be created in some sectors as a result of spending on pollution controls (i.e., "green jobs") as well as jobs lost due to higher electricity prices and other negative impacts.

Table ES-3. U.S. Economic Impacts, 2012-2020

	Annual Average	Cumulative
Employment	-183,000 jobs	-1.65 million job-years
Gross Domestic Product	-$29 billion	-$190 billion
Disposable Personal Income	-$34 billion	-$222 billion
Disposable Personal Income per Household	-$270	-$1,750

Note: All dollar values are in 2010$.
The cumulative employment impact is an undiscounted sum from 2012 to 2020; the cumulative GDP and disposable personal income impacts are present values as of January 1, 2011 using a real annual discount rate of 7 percent.
Disposable personal income impacts per capita from REMI were converted to disposable personal income impacts per household based on a current average U.S. household size of 2.58 people (Census 2011).
Source: NERA calculations as explained in text

Over the period from 2012 to 2020, about 183,000 jobs per year are predicted to be lost on net due to the effects of the four regulations. The cumulative effects mean that over the period from 2012 to 2020, about 1.65 million job-years of employment would be lost. As noted, these net employment losses reflect net gains in some sectors and net losses in others. Of the 70 sectors in the REMI PI+ model, sectors that would gain jobs account for about 55,000 added jobs per year on average, and sectors that would lose jobs account for about 238,000 fewer jobs per year on average. On a cumulative basis over the period from 2012 to 2020, the sectors that would gain jobs represent about 499,000 job-years, and the sectors that would lose jobs represent about 2,149,000 job-years.

Table ES-3 also shows the potential near- to medium-term impacts on GDP and disposable personal income. U.S. GDP would be reduced by $29 billion each year on average over the period, with a cumulative loss from 2012 to 2020 of $190 billion (2010$). U.S. disposable personal income would be reduced by $34 billion each year on average over the period, with a cumulative loss from 2012 to 2020 of $222 billion (2010$). The average annual loss in disposable personal income per household is $270, with a cumulative present value loss of about $1,750 (2010$) over the period from 2012 to 2020. Annual economic impacts from 2012 to 2020 are provided in Appendix D.

I. Introduction

This report examines various effects of environmental regulations being developed by the U.S. Environmental Protection Agency (EPA) that affect the electric utility sector. We focus on the cumulative effects of four major environmental regulations on the energy sector and on economic activity, including employment and other measures.

A. Background

EPA has proposed major air emissions and other regulations in recent years. The two air regulations that are likely to have the greatest effect on the electric utility sector are the Cross-State Air Pollution Rule (CSAPR) and the regulations of mercury and other hazardous air emissions under Section 112 of the Clean Air Act (Utility MACT). These two regulations are at different stages of development. CSAPR was promulgated as a final rule in August 2011 (although there are some outstanding issues that EPA continues to review). Utility MACT was proposed in May 2011 and is expected to be made final in November 2011.

In addition to these two major air emissions rules, electric utility plants face other potential environmental regulatory requirements that would require additional investments. EPA recently has proposed a regulation under Section 316(b) of the Clean Water Act that regulates cooling water intake structures from electric power plants (and other facilities) in order to reduce losses to fish and other aquatic organisms. In addition, EPA has proposed regulations under the Resource Conservation and Recovery Act that would change how some plants manage their solid waste streams (the ashes from the burned coal and the sludge from their flue gas desulfurization (FGD) systems). Our assessments focus on the two air emission regulations and the 316(b) and CCR regulations; electricity generating units face environmental costs for other potential regulatory requirements—notably including those related to greenhouse gases—that are not included in our estimated impacts.

The EPA has developed assessments of the potential impacts of these various regulations and proposed regulations in separate regulatory impact analyses (RIAs). These RIAs provide important information on the potential social costs and social benefits of the proposed regulations as well as their potential effects on the energy sector. The public comments provide other information on the potential effects of the individual rules. Information on individual regulations, however, is limited because it does not measure the cumulative effects of many potential regulatory requirements either on individual power plants or on energy markets.

In the face of the limited information provided by evaluating individual regulations, various studies have evaluated the combined effects of various EPA regulations. Most of the studies have evaluated impacts on potential retirements of coal-fired units and some studies have estimated potential implications for electricity system reliability.[5] These studies differ substantially in the

5 See Bipartisan Policy Center (2011), Brattle Group (2010), Charles River Associates (2010b), Edison Electric Institute (2011), ICF International (2010), M.J. Bradley & Associates and Analysis Group (2011), and North American Electric Reliability Corporation (2010). Note that the ability of these national studies to evaluate

environmental regulations they evaluate and in the nature of their evaluations. The prospect of substantial expenditures for pollution controls results in additional projected coal unit retirements, as every prior study has found.

The potential economic impacts of these rules—including their potential effects on employment and other measures of economic activity—have been less studied than their impacts on potential coal unit retirements, although some studies have considered potential economic impacts of some aspects of the regulations. For example, Ceres (2010) has developed estimates of the potential positive effects of the regulations on employment related to expenditures for emission controls. As various commentators have noted, however, this study did not provide information on the potential negative effects of higher electricity prices and other means of financing the added costs (see, e.g., Montgomery 2011). To our knowledge, no other study has estimated the cumulative economic impacts that include both the positive and negative effects of these four major regulations.

B. Objectives of This Report

The overall objective of this report is to provide estimates of the cumulative energy and economic effects of these four environmental regulations over the period from 2012 to 2020. That is, we consider the potential effects of these regulations on energy markets as well as on employment and other measures of economic activity. We have developed a modeling framework to estimate these various effects. We emphasize, however, that we have not developed estimates of the potential social benefits and social costs of these regulations and do not evaluate whether the individual regulations—or possible regulatory alternatives—would be desirable from a societal perspective.

In particular, the assessments presented in this study include the following three major types of effects.

1. *Coal unit retirements*. We consider the potential effects of regulatory requirements on coal unit retirement decisions based upon various key uncertainties, including the level of future natural gas and coal prices as well as the level of compliance costs. We use the results from this modeling framework to develop potential ranges of total U.S. coal unit retirements.

2. *Energy market effects*. We use information on predicted coal unit retirements as well as information on control costs for units that are not expected to retire to develop estimates of the potential effects of the policies on electricity and other energy markets. The results include estimates of the total compliance costs for the electricity sector due to the regulations, including control costs (capital as well as operation and maintenance), changes in fuel costs, and the costs of additional capacity added.

3. *Economic impacts*. The economic impacts of the regulations—including effects on employment, gross domestic product (GDP), and disposable personal income (i.e., personal

impacts on electricity system reliability is limited, since reliability impacts are likely to be sensitive to various system details (e.g., local transmission and voltage constraints) that are not included in the studies.

income after taxes)—are estimated by using the energy impacts in an economic impact model.

There are substantial uncertainties involved in developing these estimates. As discussed below, the model we use to develop estimates of coal unit retirements incorporates key uncertainties. It is important to emphasize, however, that other uncertainties are not modeled—including the possibility that coal and other units will face potential regulations related to greenhouse gases—and thus the projections presented in this report should be viewed as estimates of the likely impacts of only the four policies evaluated.

C. Outline of This Report

The remainder of this report is organized as follows. Chapter II provides an overview of the methodologies that are used and the policies that are evaluated in the study. Chapter III presents the results of the analyses. The appendices provide details on the models, compliance assumptions, methodologies, and results.

II. Overview of Methodologies and Policies

This chapter provides summary information on the methodologies used to estimate the potential economic impacts of the four policies. We also provide overviews of the four environmental policies that are modeled. Additional details of the models, policies, and data are provided in the appendices.

A. Modeling Framework

The methodology used in this study is based upon a set of linked models designed to assess the energy and economic impacts of environmental regulations affecting the electric utility sector. The empirical estimates of policy impacts are developed by comparing impacts under a baseline case (i.e., a case without the policies in place) and impacts under the policy case.

1. Overview of Modeling Framework

The modeling framework consists of three principal elements:

1. *Retirement Model*, which estimates whether coal units would be expected to retire based upon comparisons of the expected value of the future costs for the coal unit—including the likely potential costs of additional environmental controls—and the expected costs of an equivalent new natural gas combined cycle unit;

2. *National Energy Modeling System* (NEMS) model developed by the U.S. Energy Information Administration (EIA), which we use to assess the likely effects of compliance costs and coal unit retirements on the energy markets; and

3. *Policy Insight Plus model developed by Regional Economic Models, Inc. (REMI PI+)*, which we use to develop estimates of the economic impacts of energy market effects.

The following sections provide summaries of these elements.

2. Coal Unit Retirement Model

Power companies face the choice of retrofitting existing coal units to meet regulations or retiring them if the future costs do not justify continued operation in light of the likely costs of alternative sources to meet future electricity demand. We developed a detailed model to evaluate whether existing coal units in the United States would be expected to retire taking into account the potential costs of retrofit (and other future costs) as well as uncertainties in energy prices and other factors.

The retirement model is designed to mirror the decision by power companies on whether to retrofit coal-fired units with environmental controls or retire them and replace them with new capacity. A Monte Carlo formulation takes into account major uncertainties involved in this decision.

The model begins with estimates of the potential additional costs related to environmental policies. The potential future costs for coal units are based upon EIA data on unit characteristics (including capacity, capacity factor, heat rate, O&M costs, coal type, and current environmental controls) and on EPA information on the potential costs of the various controls. The potential technologies and costs for each coal-fired unit also reflect the flexibility that CSAPR provides—due to the potential for emissions trading—as well as the fuel and electricity prices based upon a similar level of retirements.[6] The model thus takes account of the feedback effects of coal unit retirements on electricity and fuel prices.

The model uses statistical techniques and EPA data to simulate hourly electricity prices in each region—as a function of natural gas prices, time of day, season, peak/off-peak, and other factors—and generation decisions by coal units and potential replacement capacity, with generation a function of price and marginal cost. Uncertain parameters include the costs of controls, fuel prices and electricity prices, and the costs of the likely replacement alternative (a new natural gas combined cycle unit), with interactions among the uncertain parameters included in the Monte Carlo formulation.

Future coal unit costs are compared with the future costs of a new natural gas combined cycle unit by calculating the difference between the cost of the coal unit and the cost of the natural gas alternative in each of the 100 Monte Carlo draws. The unit is presumed to retire if the expected value of the cost difference is positive, i.e., on expectation, the coal unit would have greater future costs than a new natural gas combined cycle unit. Existing coal unit remaining lifetimes in these calculations are assumed to range between 10 and 20 years, depending upon unit age in 2015, to reflect the likelihood that owners of older units will have a shorter time horizon for recovering the cost of additional controls. The formulation accounts for the costs of using system energy during hours when coal units and the potential replacement capacity would not run.

3. NEMS Model

The National Energy Modeling System (NEMS) is a computer-based, energy-economy modeling system of the U.S. through 2030. NEMS projects the production, imports, conversion, consumption, and prices of energy, subject to assumptions on macroeconomic and financial factors, world energy markets, resource availability and costs, behavioral and technological choice criteria, cost and performance characteristics of energy technologies, and demographics. NEMS was designed and implemented by the Energy Information Administration (EIA) of the U.S. Department of Energy (DOE).

4. Regional Economic Models, Inc. Policy Insight Plus Model

The Regional Economic Models, Inc. (REMI) Policy Insight Plus (PI+) model produces estimates of the changes in employment, GDP, disposable personal income, and other macroeconomic variables due to changes in supply, demand, prices, and other types of inputs. Each version of the REMI PI+ model is custom-built for the regions of interest, which can range

[6] We develop the implications of emissions trading flexibility provided by CSAPR by running the NEMS model with the relevant caps. The technologies identified in this run for each unit are used in the retirement model.

from counties to entire countries. The REMI PI+ model incorporates detailed and up-to-date macroeconomic data from the U.S. Bureau of Economic Analysis, the U.S. Bureau of Labor Statistics, the U.S. Census Bureau, and other public sources. The REMI PI+ model is widely used by federal, state, and local agencies, as well as analysts in the private sector and academia, to estimate the effects of regulations, investments, closures, and other scenarios.

B. Overview of Policies Modeled

This section summarizes the four policies evaluated in this report, including the two air emission regulations (CSAPR and Utility MACT) as well as Section 316(b) and CCR. Appendix A provides details on how the reference case and the four policies are modeled, including information on the control cost assumptions that are used.

1. Reference Case

The version of NEMS used for the model represents current legislation and environmental regulations as of January 31, 2011. The policies included in the reference case include state requirements for reduction of mercury emissions but not the Clean Air Mercury Rule, which was vacated and remanded by the D.C. Circuit Court of the U.S. Court of Appeals on February 8, 2008. The reference case also includes the temporary reinstatement of the SO_2 and NOx cap-and-trade programs included in the Clean Air Interstate Rule (CAIR) as a result of the ruling issued by the United States Court of Appeals for the District of Columbia on December 23, 2008.[7] CAIR is included in the reference case through 2011. From 2012 onward, SO_2 and NOx caps revert to pre-CAIR levels.

Proposed federal and state legislation, regulations, or standards—and sections of legislation that have been enacted but require funds or implementing regulations that have not been provided or specified—are not reflected in the reference case. The excluded policies include the four policies evaluated in our study.[8]

2. Cross-State Air Pollution Rule

EPA promulgated CSAPR in August 2011, following a draft rule (Clean Air Transport Rule, or CATR) proposed in August 2010 as a replacement to CAIR. CSAPR requires 27 states to reduce power plant emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x) from power plants in Eastern states in an effort to improve ozone and fine particulate air quality in other downwind states.[9] Under CSAPR, EPA set new limits on SO_2 and NO_x emissions for each state beginning in 2012. The limits tighten in some states in 2014.

---

7 EPA finalized CAIR in 2005 but the rule was remanded to EPA by the D.C. Circuit Court of Appeals in 2008. The court decision required EPA to develop a different regulatory approach but to implement CAIR in the meantime.

8 Note that we include CSAPR in our assessments although EPA finalized CSAPR in August 2011 (EPA 2011a).

9 In a separate but related regulatory action, EPA also issued a supplemental notice of proposed rulemaking to require six states to make summertime NOx reductions under the CSAPR ozone-season program. Finalizing this

3. Utility MACT

EPA proposed the Utility MACT rule in May 2011 to reduce emissions of mercury and other hazardous air pollutants (including other hazardous metals and acid gases) from coal- and oil-fired power plants across the country. The rule would set emission rate standards for different types of coal- and oil-fired units based on maximum achievable control technology. The emission rate standards would apply to mercury, other non-mercury metallic hazardous air pollutants (using particulate matter as a proxy), and acid gases (using hydrogen chloride as a proxy). Covered power plants would have up to three years to comply with the rule, but permitting authorities could grant one-year extensions to power plants if they required additional time.

4. Coal Combustion Residuals

EPA issued a proposed rule on June 21, 2010 related to the regulation of coal combustion residuals (also referred to as coal combustion waste) under the Resource Conservation and Recovery Act (RCRA). The regulations apply to the management of coal combustion residuals generated by steam electric power plants (i.e., electric utilities and independent power producers) that are disposed of in landfills and surface impoundments.

EPA co-proposed two approaches to the regulation of coal combustion waste. The first would regulate residuals under Subtitle C of RCRA as a "special waste." The second would regulate residuals under Subtitle D as a non-hazardous waste. Our assessments are based on the potential costs to individual units of regulating coal combustion residuals under Subtitle D.

5. Clean Water Act Section 316(b)

On April 20, 2011, EPA proposed cooling water intake requirements for existing power plants and other industrial facilities under Section 316(b) of the Clean Water Act. These facilities withdraw water and in the process, fish and other aquatic organisms are lost if they become trapped against intake screens ("impingement") or pulled into the cooling system ("entrainment"). Various technologies reduce impingement and entrainment losses, including the retrofit of plants with cooling towers to provide closed-cycle cooling.

EPA evaluated four alternatives for setting Section 316(b) standards, with Option 1 identified as its preferred option. Option 1 would require that existing plants withdrawing water above a proposed 2 million gallon per day threshold reduce the impingement mortality by meeting various national standards (EPA 2011b, pp. 22203-22204). In contrast, entrainment controls would be set on the basis of site-specific requirements. Under EPA's proposal, permit writers will be required to consider converting the condenser cooling system from once-through cooling to closed-cycle cooling through the use of cooling towers, which reduces net flow and thus entrainment losses (albeit at substantial cost and often undesirable environmental side-effects). EPA estimated the cost of installing cooling towers under Option 1 at the 46 fossil units with the

supplemental program would bring the total number of covered states under the CSAPR to 28. EPA reports that it is proposing to finalize this proposal by late fall 2011.

largest cooling water withdrawals from tidal waters. Our assessments are based on the potential costs to individual units of the Option 1 alternative.

III. Study Results

This chapter summarizes the study results for our analyses of the cumulative energy and economic impacts of the four environmental policies. The results are grouped into three categories: (1) coal unit retirements; (2) energy market effects; and (3) economic impacts. Additional details are provided in the appendices.

A. Coal Unit Retirements

1. National Results

The potential costs of the four policies are estimated to lead to 39 gigawatts (GW) of prematurely retired capacity among the current coal-fired power plants. This figure represents additional retirements above those in the reference case (i.e., retirements predicted without the four regulations in place) and accounts for about 12 percent of the 2010 U.S. coal-fired electricity generating capacity. As noted, this estimate does not include the potential effects of other potential requirements—notably potential greenhouse gas emission regulations—or concerns related to detailed electricity system reliability.

We developed an assessment of the potential range of possible retirements using the information from the 100 individual draws from the retirement model. We calculated the retirements in each of the draws as a sensitivity analysis, assuming that a unit would retire if its future costs were greater that the future costs of the natural gas unit in those circumstances. The range of retirements was from 17 GW to 79 GW in these 100 cases. This range is roughly consistent with sensitivity results from other studies, although the other studies do not use the same assumptions and methodology.[10]

2. Uncertainties Regarding Estimated Retirements

The range of potential retirements provides an indication of the substantial uncertainty surrounding potential retirements due to uncertainties in future natural gas prices, control costs and other factors influencing individual retirement decisions. There are, however, some factors that are not included in the retirement model. The retirement model does not account for the possibility that adjustments could occur if the local effects of retirements were severe (e.g., likely to impair electricity system reliability). These adjustments would tend to reduce the actual level of retirements below those predicted by our model, which is based upon economic calculations, although the potential impacts on electricity prices could be greater than estimated assuming units are allowed to retire.

In addition, the model does not factor into the calculation of expected future costs the potential costs and other impacts associated with greenhouse gas regulations. Even without the prospect of

[10] EIA, for example, reports a range of retirements for the two air emissions regulations from 4.7 GW to 63.8 GW (net of reference case retirements) depending upon the level of future natural gas prices as well as the likely time horizon for amortizing compliance capital costs (EIA 2011, p. 50).

specific regulatory requirements, owners of coal-fired power plants are likely to reflect the prospect of potential greenhouse gas regulations in their decisions on whether to incur large compliance expenditures or retire their units. Our estimates do not take into account these effects, which would lead to greater coal unit retirements.

3. Regional Results

The expected coal unit retirements differ substantially among electricity regions. Table 1 shows the potential coal unit retirements by North American Electric Reliability Corporation (NERC) region.[11] The table also shows the percentage of 2010 coal capacity in each region that is predicted to retire by 2015 and each region's share of total U.S. retirements. Note that most retirements are in the Mid-Atlantic and Great Lakes and Southeast regions. These results are consistent with the results of other studies (e.g., Brattle Group 2010).

Table 1. Regional Retirement Estimates

		2010 Coal Capacity (GW)	Retirements (GW)	% of Regional 2010 Coal Cap	% of Total Retirements
	U.S. Total	318.1	39.1	12%	100%
NERC Regions					
NPCC	Northeast	5.7	1.3	22%	3%
RFC	Mid-Atlantic and Great Lakes	107.8	14.5	13%	37%
SERC	Southeast	98.5	18.0	18%	46%
FRCC	Florida	10.3	0.1	1%	0%
MRO	Upper Midwest	28.8	1.9	6%	5%
SPP	Oklahoma and Kansas	19.0	1.6	9%	4%
ERCOT	Texas	18.2	0.6	3%	1%
WECC	West	29.8	1.2	4%	3%

Source: NERA calculations as explained in text

B. Electricity and Energy Market Impacts

As described in the previous section, we used NEMS to estimate net changes in coal-fired generation, natural gas-fired generation, fuel prices, and electricity prices as a result of coal unit retirements and environmental controls due to the four policies.

1. National Results

Table 2 summarizes the potential costs for the electricity sector based on the level of coal retirements predicted in the retirement model. These costs include compliance costs for coal units that do not retire, capital costs for new capacity that would replace retiring coal units, and changes in fuel costs. Costs are projected to be approximately $21 billion (in 2010$) per year over the period from 2012 to 2020. The costs represent a total of $127 billion (present value in

[11] NEMS provides information for 22 regions; we have aggregated the results into the eight major NERC regions.

2010$ as of January 1, 2011) over the period from 2012 to 2020. Capital costs for environmental controls and replacement capacity are approximately $104 billion.[12]

Table 2. Electricity Sector Costs, 2012-2020 (billion 2010$)

	Annual Avg	PV
Environmental Controls	$15	$89
Replacement Capacity	$2	$11
Fuel	$5	$28
Total	$21	$127

Note: Compliance costs from 2012 through 2020 are discounted to January 1, 2011 using a real annual discount rate of 7 percent.
Annual average costs are based on the present values and discounting.
The cost of environmental controls includes cost savings for operating and maintenance (O&M) expenses.
Source: NERA calculations as explained in text

Table 3 summarizes the average effects of the four policies at the national level over the period from 2012 to 2020. (Detailed annual impacts are provided in Appendix C, with effects that are both higher and lower than these average values.)

Table 3. Average Annual Energy Market Impacts, 2012-2020

	Coal Retirements (GW)	Coal-Fired Generation (million MWh)	Coal Price at Minemouth (2010$/ton)	Gas-Fired Generation (million MWh)	Gas Price at Henry Hub (2010$/MMBtu)	Avg Retail Elec Price (2010$/MWh)
	Average of 2012-2020 Projections					
Reference	3.1	1,911	$33.54	639	$4.48	$86.87
CSAPR+MACT+CCR+316(b)	42.2	1,699	$31.61	765	$4.95	$92.52
	Change from Average of 2012-2020 Reference Projections					
CSAPR+MACT+CCR+316(b)	+39.1	-212	-$1.93	+126	+$0.48	+$5.65
	% Change from Average of 2012-2020 Reference Projections					
CSAPR+MACT+CCR+316(b)	+1241%	-11.1%	-5.7%	+19.7%	+10.7%	+6.5%

Note: Coal retirements are cumulative from 2010 through 2020.
Source: NERA calculations as explained in text

The potential impacts of the four policies on energy markets are substantial.

- Coal-fired generation is predicted to decrease substantially, by an average of 11.1 percent relative to average reference case levels over the 2012-2020 period.

- In contrast, natural gas-fired generation is predicted to increase substantially, by an average of 19.7 percent relative to average reference case levels over the same period.

[12] Capital costs exceed the total for environmental controls and replacement capacity because of net reductions in operating and maintenance costs.

- Average coal prices are predicted to decline, reflecting the reduction in coal-fired generation. Coal prices decline an average of 5.7 percent relative to average reference case levels over the same period.

- Average natural gas prices are predicted to increase, reflecting the increased demand for gas-fired generation. Henry Hub natural gas prices increase an average of 10.7 percent relative to average reference case levels over the 2012-2020 period. These prices increases would increase costs by about $8 billion per year for residential, commercial, and industrial customers (and a total of about $52 billion as a present value as of January 1, 2011 over the period).

- Average retail electricity prices are predicted to increase an average of 6.5 percent over the same period.

It is useful to put these predicted impacts into perspective. For example, the predicted effect of the four policies on Henry Hub natural gas prices is $0.48/MMBtu. By way of context, the EIA reduced its forecast of future Henry Hub natural gas prices by approximately $2/MMBtu from AEO 2009 to AEO 2011.

2. Uncertainties Regarding Energy Market Impacts

The projected energy market impacts due to the four environmental policies are significant. The impacts arise both because of substantial compliance costs—that lead a substantial number of coal-fired units to retire and force other coal units to incur substantial retrofit costs in order to comply—and because of the market reactions to these initial impacts.

The impacts depend upon many factors, including the baseline conditions—including projected future natural gas prices—as well as the details of the market reactions to the policy changes that are embedded in the NEMS model. The baseline also includes assumptions on the nature of future regulatory requirements. As noted above, we modified the baseline in NEMS to evaluate the impacts of these air emission policies relative to the absence of similar SO_2 and NOx policies (no CAIR from 2012 onward); EPA made the same assumption in its recent analysis of CSAPR. We have included state mercury requirements in the baseline, which tend to decrease the impacts relative to a baseline without the state requirements.

The electricity market impacts also depend upon a host of specific elements of the electricity systems in various regions. Some of these elements are included in the assessments, such as the nature of the state regulatory regime. The NEMS results, however, do not include considerations related to highly location-specific factors such as transmission security and the time constraints on retiring units, particularly relatively large units (ICF 2011).

3. Regional Results

NEMS provides energy price results for various regions, including 22 electricity price regions. The electricity price impacts of the four policies differ by region depending upon many factors including the following:

- reliance on coal-fired generation under baseline conditions;
- coal unit retirements;
- need for replacement capacity;
- type of replacement capacity that NEMS builds;
- retrofits for coal units that continue to operate as well as the costs of those retrofits;
- capacity factors for coal units;
- regional fuel prices;
- interregional electricity trade; and
- regulatory regime.

Table 4 provides estimates of the percentage increases in retail electricity rates in the 22 NEMS electricity regions due to the four policies. As with the prior results, these figures are based upon the average percentage changes over the period from 2012 to 2020. (Detailed annual impacts are provided in Appendix C, with effects that are both higher and lower than these average values.)

Table 4. Average Electricity Price Impacts, 2012-2020

		2010$/MWh	%
	US Average	+$5.65	+6.5%
NEMS Regions			
NEWE	New England	+$2.93	+2.2%
NYCW	NYC	+$6.97	+4.2%
NYLI	NY Long Island	+$13.00	+8.0%
NYUP	NY Upstate	+$6.39	+5.6%
RFCE	Mid-Atlantic	+$10.38	+10.7%
SRVC	VA & Carolinas	+$4.05	+5.1%
SRSE	Southeast	+$6.94	+8.2%
FRCC	Florida	+$4.10	+3.9%
RFCM	Lower MI	+$7.63	+9.6%
RFCW	OH, IN, & WV	+$7.01	+8.6%
SRCE	KY & TN	+$8.36	+13.5%
MROE	WI & Upper MI	+$6.96	+9.2%
MROW	Upper Midwest	+$5.39	+7.8%
SRGW	South IL & East MO	+$6.73	+11.1%
SPNO	KS & West MO	+$6.42	+8.0%
SRDA	AR, LA, & West MS	+$5.16	+7.2%
SPSO	Oklahoma	+$8.75	+12.6%
ERCT	Texas	+$5.34	+6.9%
RMPA	CO & East WY	+$1.40	+1.5%
NWPP	Northwest	+$0.04	+0.1%
AZNM	AZ & NM	+$1.40	+1.6%
CAMX	California	+$2.25	+1.6%

Source: NERA calculations as explained in text

C. Economic Impacts

As noted, we used the REMI PI+ model to estimate the potential near- and medium-term economic impacts of the four policies based upon the energy market impacts estimated in NEMS.

1. Results

Table 5 summarizes the effects of the four policies on various economic impact measures, including impacts on employment, GDP, and disposable personal income. The table includes information on the average annual changes over the period from 2012 to 2020 as well as the cumulative effects over the period (detailed annual impacts are provided in the appendices).

Table 5. U.S. Economic Impacts, 2012-2020

	Annual Average	Cumulative
Employment	-183,000 jobs	-1.65 million job-years
Gross Domestic Product	-$29 billion	-$190 billion
Disposable Personal Income	-$34 billion	-$222 billion
Disposable Personal Income per Household	-$270	-$1,750

Note: All dollar values are in 2010$.
The cumulative employment impact is an undiscounted sum from 2012 to 2020; the cumulative GDP and disposable personal income impacts are present values as of January 1, 2011 using a real annual discount rate of 7 percent.
Disposable personal income impacts per capita from REMI were converted to disposable personal income impacts per households based on a current average U.S. household size of 2.58 people (Census 2011).
Source: NERA calculations as explained in text

Over the period from 2012 to 2020, about 183,000 jobs per year are predicted to be lost on net due to the effects of the four regulations. The cumulative effects mean that over the period from 2012 to 2020, about 1.65 million job-years of employment would be lost. U.S. GDP would be reduced by $29 billion each year on average over this period, with a cumulative loss from 2012 to 2020 of $190 billion (2010$). U.S. disposable personal income would be reduced by $34 billion each year on average over this period, with a cumulative loss from 2012 to 2020 of $222 billion (2010$). The average annual loss in disposable personal income per household is $270, with a cumulative loss of $1,750 (2010$).

The four policies would lead to different net employment impacts on different sectors. Of the 70 sectors in the REMI PI+ model, sectors that would gain jobs account for about 55,000 added jobs per year on average, and sectors that would lose jobs account for about 238,000 fewer jobs per year on average. On a cumulative basis over the period from 2012 to 2020, the sectors that would gain jobs represent about 499,000 job-years, and the sectors that would lose jobs represent about 2,149,000 job-years.

2. Uncertainties Regarding Economic Impacts

The estimated economic impacts of the four environmental policies over the period from 2012 to 2020 are substantial. These impacts include many factors, including: the positive impacts of expenditures on environmental controls and replacement electricity capacity; the negative effects of reduced coal sales and reduced coal production; the positive effects of increased natural gas sales; both the negative effects of higher natural gas prices on consumers and the positive effects on producers; and the negative effects of electricity price effects on consumers. In addition, the timing of impacts depends upon how the capital costs of pollution controls and increased replacement capacity are financed. The overall impacts are thus a complicated result of a large number of positive and negative factors.

These estimates are subject to various types of uncertainties, including uncertainties regarding the energy market and other inputs. As noted above, the coal unit retirements and energy market impacts are subject to various uncertainties, which translate into uncertainties regarding the economic impacts. There are additional uncertainties regarding the modeling of these economic impacts. The macroeconomic modeling does not, for example, take into account the potential negative effect on the overall productivity and growth of the economy of reduced productive investment due to the financing of pollution control expenditures. The model also does not presume that environmental compliance expenditures use any unemployed or idle resources. In addition, the model assumes that consumers can shift away from more expensive energy and thus reduce the negative impacts of higher natural gas and electricity prices, an assumption that may understate the likely negative impacts of the price increases.

IV. References

Bipartisan Policy Center. 2011. *Environmental Regulation and Electric System Reliability.* Washington, D.C.: Bipartisan Policy Center.

Brattle Group. 2010. *Potential Coal Plant Retirements Under Emerging Environmental Regulations*. Cambridge, MA: Brattle Group, December 8.

Ceres. 2011. *New Jobs—Cleaner Air: Employment Effects Under Planned Changes to the EPA's Air Pollution Rules*. Report prepared by the University of Massachusetts Political Economy Research Institute. Boston: Ceres, February.

Charles River Associates. 2010a. *Prospects for an EPA-Driven Capital Crisis for Utilities.* Boston, MA: CRA, September.

Charles River Associates. 2010b. *A Reliability Assessment of EPA's Proposed Transport Rule and Forthcoming Utility MACT*. Washington, D.C.: CRA, December.

Edison Electric Institute. 2011. *Potential Impacts of Environmental Regulation on the U.S. Generation Fleet*. Report prepared by ICF International. Washington, D.C.: EEI, January.

Electric Power Research Institute. 2010. *Cost Analysis of Proposed National Regulation of Coal Combustion Residuals from Electric Generating Industry.* Palo Alto, CA: EPRI, November.

ICF International. 2010. *Clean Air, Ash and Water Regulations: Potential Impact of EPA Proposed Rules.* Fairfax, VA: ICF, October.

ICF International. 2011. *Retiring Coal Plants While Protecting System Reliability.* Fairfax, VA: ICF, August.

M.J. Bradley & Associates and Analysis Group. 2011. *Ensuring a Clean, Modern Electric Generating Fleet while Maintaining Electric System Reliability.* Concord, MA: M.J. Bradley & Associates, June.

Montgomery, W. David. 2011. *Prepared Testimony of W. David Montgomery, Ph.D., before the Senate Committee on Environment and Public Works, Subcommittee on Green Jobs and the New Economy.* February 15.

North American Electric Reliability Corporation. 2010. *2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations*. Princeton: NERC, October.

U.S. Census Bureau. 2011. "Profile of General Population and Housing Characteristics: 2010." (factfinder2.census.gov/faces/nav/jsf/pages/index.xhtml, accessed September 20, 2011)

U.S. Energy Information Administration. 2011. *Annual Energy Outlook 2011*. Washington, D.C.: EIA, April. (www.eia.gov/forecasts/aeo/pdf/0383(2011).pdf, accessed September 20, 2011)

U.S. Environmental Protection Agency. 2005. "Rule To Reduce Interstate Transport of Fine Particulate Matter and Ozone (Clean Air Interstate Rule); Revisions to Acid Rain Program; Revisions to the NOX SIP Call; Final Rule." 70 *Federal Register* 25162. Washington, D.C.: EPA, May 12.

U.S. Environmental Protection Agency. 2010. "Federal Implementation Plans To Reduce Interstate Transport of Fine Particulate Matter and Ozone; Proposed Rule." 75 *Federal Register* 45210. Washington, D.C.: EPA, August 2.

U.S. Environmental Protection Agency. 2011a. "Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals." 76 *Federal Register* 48208-48483. Washington, D.C.: EPA, August 8. (www.gpo.gov/fdsys/pkg/FR-2011-08-08/pdf/2011-17600.pdf, accessed September 20, 2011)

U.S. Environmental Protection Agency. 2011b. "National Pollutant Discharge Elimination System—Cooling Water Intake Structures at Existing Facilities and Phase I Facilities; Proposed Rule." 76 *Federal Register* 22174-22288. Washington, D.C.: EPA, April 20. (www.gpo.gov/fdsys/pkg/FR-2011-04-20/pdf/2011-8033.pdf, accessed September 20, 2011)

Appendix A: Compliance Measures and Cost Estimates

This appendix provides information on the data and methodologies used to model potential compliance measures and compliance costs at coal units for relevant environmental policies in the reference case and the four potential EPA regulations (CSAPR, MACT, CCR, and 316(b)). We begin with information related to the reference case and then provide information related to each of the potential EPA regulations. We present our cost assumptions for air emission control technologies, which we used as inputs for both the reference case and policy case, at the end of this appendix.

A. Reference Case

As discussed in the report body, we modeled the energy market impacts of the potential EPA regulations using the National Energy Modeling System (NEMS), a comprehensive U.S. energy model developed and maintained by the U.S. Energy Information Administration (EIA). With the exception of the environmental policy inputs discussed in this appendix, we used the same inputs to NEMS as EIA used for its *Annual Energy Outlook* (*AEO*) *2011* (EIA 2011a). Note that the inputs for *AEO 2011* which we did not modify include inputs related to various national, regional, and state environmental policies that are currently in place, such as state renewable portfolio standards and the Regional Greenhouse Gas Initiative.

The environmental policies in the reference case that are most relevant to the potential EPA regulations are the Clean Air Interstate Rule (CAIR) to reduce SO_2 and NO_x emissions from power plants and policies to reduce mercury emissions from power plants. EIA describes its inputs related to these policies for *AEO 2011* in EIA (2011b, pp. 104-107). Table A-1 summarizes our compliance assumptions related to these policies for our reference case.

Table A-1. Compliance Assumptions for Reference Case

Policy	Emission	Compliance Assumptions
CAIR	SO_2	Apply Phase 1 SO_2 cap (3.6 million tons) through 2011 and allow NEMS to determine which units would need to install SO_2 control technologies or switch to lower-sulfur coal in the interstate cap-and-trade program; from 2012 onward, allow SO_2 cap to revert to pre-CAIR level (based on Acid Rain Program)
	NO_x	Apply Phase 1 NO_x cap (1.5 million tons) through 2011 and allow NEMS to determine which units would need to install NO_x control technologies in the interstate cap-and-trade program; from 2012 onward, allow NO_x cap to revert to pre-CAIR level (based on NO_x Budget Trading Program)
State policies	Mercury	Include mercury reductions as required by state policies and allow NEMS to determine which units would need to install mercury control technologies

Source: NERA assumptions as explained in text

1. Clean Air Interstate Rule

EPA promulgated CAIR in 2005 to reduce SO_2 and NO_x emissions from power plants in 28 Eastern states (EPA 2005).[1] EPA established interstate cap-and-trade programs for both types of emissions. The caps for both types of emissions became tighter over two phases. The NO_x program consisted of Phase 1 (2009-2014) with a cap of 1.5 million tons and Phase 2 (2015 onward) with a cap of 1.2 million tons. The SO_2 program consisted of Phase 1 (2010-2014) with a cap of 3.6 million tons and Phase 2 (2015 onward) with a cap of 2.5 million tons. In December 2008, the U.S. Court of Appeals for the D.C. Circuit remanded CAIR to EPA but did not vacate it, thus allowing the first phases of the NO_x and SO_2 programs to take effect while EPA developed a replacement rule.

Our modeling for the reference case reflects that the CAIR Phase 1 programs have taken effect. We applied the CAIR Phase 1 caps for SO_2 and NO_x emissions (using EIA's inputs for *AEO 2011*) through 2011 and allowed NEMS to decide which units would need to install SO_2 control technologies or switch to lower-sulfur coal in the interstate cap-and-trade program. Our NEMS inputs for the reference case also include the SO_2 and NO_x control technologies that coal units have installed or have announced that they will install to comply with CAIR requirements (or any state or local policies requiring reductions in these emissions). EIA (2011, p. 106) summarizes the recent and planned retrofits for SO_2 and NO_x policies that are in NEMS.

As discussed in the report body and below, EPA has promulgated the Cross-State Air Pollution Rule (CSAPR) as a replacement for CAIR to take effect in 2012 (EPA 2011a). CSAPR would cover a somewhat different set of Eastern states than CAIR but would also involve interstate cap-and-trade programs and would set the caps at similar levels to CAIR. Thus, including CAIR in our reference case from 2012 onward would make it difficult to isolate the incremental impacts of CSAPR. We therefore terminated the CAIR Phase 1 caps after 2011 in our reference case and reverted SO_2 and NO_x caps to pre-CAIR levels (based on the Acid Rain Program and NO_x Budget Trading Program, respectively). Note that EPA also removed future CAIR caps from its reference case for modeling the incremental impacts of CSAPR (EPA 2011b, pp. 30-32).

2. State Mercury Policies

Seventeen states have enacted policies to limit mercury emissions from coal units (EPA 2011c, pp. 3-8). These state mercury policies vary significantly in their form, stringency, and schedule. Some policies took effect as early as 2008, while others will take effect as late as 2017.

EIA incorporated these state mercury policies into *AEO 2011*, and we used the same inputs for our reference case. To comply with these state mercury policies, some coal units install mercury control technologies such as activated carbon injection (ACI) and fabric filters in the reference case. We allowed NEMS to determine the compliance measures at coal units based on parameters built into NEMS on mercury emission rates for different types of coal and different

---

[1] SO_2 emissions from power plants in Western states are regulated under the Acid Rain Program (EPA 2010a). We did not modify the SO_2 caps for Western power plants in NEMS for our reference case or policy case.

configurations of environmental control technologies, including scrubbers and SCR (EIA 2011b, p. 105-106).

Note that when NEMS determines based on its compliance calculations that coal units will install scrubbers, the scrubbers are assumed to be wet scrubbers (EIA 2011a, p. 46). Thus, reductions in mercury emissions from scrubbers that NEMS builds to comply with state mercury requirements reflect parameters for wet scrubbers. When NEMS calculates mercury emissions from coal units with existing or planned dry scrubbers, however, the mercury emissions accurately reflect parameters for dry scrubbers. Modeling issues related to wet and dry scrubbers are discussed further in the context of MACT HCl compliance below.

B. Cross-State Air Pollution Rule

EPA promulgated CSAPR as a replacement for CAIR in August 2011 (EPA 2011a). As noted above, CSAPR would cover a somewhat different set of Eastern states (27 in total) than CAIR but would also involve interstate cap-and-trade programs and would set the caps at similar levels to CAIR. CSAPR would set caps on emissions in each state but would allow interstate trade of emission allowances provided that state emissions stay within so-called variability limits. Covered units would not be able to use allowances from the Acid Rain Program, NO_x Budget Trading Program, or CAIR for compliance with CSAPR. The caps for both SO_2 and NO_x would become tighter over two phases. The SO_2 program would consist of Phase 1 (2012-2013) with a cap of 3.4 million tons and Phase 2 (2014 onward) with a cap of 2.1 million tons. The annual NO_x program would consist of Phase 1 (2012-2013) with a cap of 1.2 million tons and Phase 2 (2014 onward) with a cap of 1.1 million tons.

Table A-2 summarizes our compliance assumptions for CSAPR.

Table A-2. Compliance Assumptions for CSAPR

Policy	Emission	Compliance Assumptions
CSAPR	SO_2	Apply SO_2 caps (3.4 million tons in 2012-2013 and 2.1 million tons from 2014 onward) and allow NEMS to determine which units would need to install SO_2 control technologies or switch to lower-sulfur coal in the interstate cap-and-trade program (within state variability limits); in order to discourage unrealistic fuel switching in the model in 2012-2013, do not allow banking of CSAPR SO_2 allowances in those years
	NO_x	Apply NO_x caps (1.2 million tons in 2012-2013 and 1.1 million tons from 2014 onward) and allow NEMS to determine which units would need to install NO_x control technologies in the interstate cap-and-trade program (within state variability limits); allow banking of CSAPR NO_x allowances

Source: NERA assumptions as explained in text

1. CSAPR SO_2 Compliance

We modeled the CSAPR SO_2 program in NEMS as an interstate cap-and-trade program with state variability limits and two phases. We allowed NEMS to determine which units would install SO_2 control technologies and which would switch to lower-sulfur coal.

CSAPR modeling by EPA indicates substantial switching among various coals in 2012 and 2013 based on their sulfur content (EPA 2011b and NERA analysis of underlying data). Although EPA's modeling results seem reasonable for the total amounts of low-sulfur and ultra-low-sulfur coal, it may not be feasible to achieve the extent of fuel switching implied in EPA's modeling due to the prevalence of long-term fuel contracts, rail networks, and other real-world practicalities for coal units to switch their coal types on such a large scale in the early years of the program. Coal units appear to switch fuels in the early years in EPA's analysis to build up a large bank of CSAPR SO_2 allowances. To avoid what seems to be potentially unrealistic fuel switching in our modeling, we include fuel switching to meet the 2012 and 2013 caps but not to build up a bank of CSAPR SO_2 allowances in the early years of the program.

2. CSAPR NO_x Compliance

We modeled the CSAPR NO_x program in NEMS as an interstate cap-and-trade program with state variability limits and two phases. We allowed NEMS to determine which units would install various NO_x control technologies. Since fuel switching is not an issue for NO_x programs, we allowed banking of CSAPR NO_x allowances in all years.

C. Utility MACT

EPA proposed the Utility Maximum Achievable Control Technology (MACT) rule in May 2011 to reduce emissions of mercury and other hazardous air pollutants (including mercury, other hazardous metals, and acid gases) from coal- and oil-fired power plants across the country. The rule would set emission rate standards for different types of coal and oil based on maximum achievable control technology. The emission rate standards would apply to mercury, particulate matter (PM) as a proxy for all non-mercury hazardous metals, and hydrogen chloride (HCl) as a proxy for all acid gases. Covered power plants would have up to three years to comply with the rule, but permitting authorities could grant one-year extensions to power plants if they required additional time. Table A-3 shows the proposed emission rate standards for mercury, particulate matter, and hydrogen chloride from existing coal units under the Utility MACT rule.

Table A-3. Proposed Utility MACT Emission Rate Standards for Existing Coal Units

Coal Rank	Mercury	Hydrogen Chloride	Particulate Matter
Bituminous and subbituminous	1.2 lb/TBtu	0.0020 lb/MMBtu	0.030 lb/MMBtu
Lignite	4.0 lb/TBtu	0.0020 lb/MMBtu	0.030 lb/MMBtu

Notes: TBtu: trillion British thermal units of fuel input
MMBtu: million British thermal units of fuel input
The mercury standard for lignite shown in the table is the "beyond-the-floor" limit; the MACT standard based on the top 12 percent of units would be 11.0 lb/TBtu.
The mercury standard for bituminous and subbituminous coal is the update from the original value of 1.0 lb/TBtu based on EPA's letter of May 18, 2011 (EPA 2011e).
Source: EPA (2011d), p. 25027

Table A-4 summarizes our assumptions for MACT.

Table A-4. Compliance Assumptions for MACT

Policy	Emission	Compliance Assumptions
MACT	Mercury	Apply mercury standards in 2015 at all units and allow NEMS to determine which units would need to install ACI, fabric filters, and/or scrubbers
	HCl	Assign costs for DSI in 2015 at unscrubbed units smaller than 300 MW that consume subbituminous coal (these units requiring DSI will also require fabric filters); require dry scrubbers at all non-DSI units that consume Western bituminous coal, subbituminous coal, or lignite (these units requiring dry scrubbers will also require fabric filters); require wet scrubbers at all units that consume Eastern bituminous coal (these units requiring wet scrubbers will not require fabric filters, but NEMS may retrofit them with fabric filters for mercury or they may require fabric filters for MACT PM compliance)
	PM	In addition to requiring fabric filters at all units with DSI or dry scrubbers, and in addition to requiring fabric filters (in combination with ACI) at some units for MACT mercury compliance, require fabric filters for MACT PM compliance at the necessary number of coal units so that the same percentage of total U.S. coal capacity has fabric filters in 2015 as in the EPA MACT RIA; use EPA's list of coal units installing fabric filters from the MACT RIA to identify the additional coal units that would require fabric filters

Source: NERA assumptions as explained in text

1. MACT Mercury Compliance

As noted above in the context of state mercury policies for the reference case, NEMS estimates mercury emissions from coal units and can determine which units would install ACI, fabric filters, and/or scrubbers to comply with mercury reduction requirements. We required mercury reductions at all U.S. coal units based on the mercury standards in Table A-3. We assumed that compliance with the mercury standards would be required by 2015. Note that our inclusion of state mercury policies in the reference case dampens the impacts of the national MACT mercury standards in the policy case, because some coal units install ACI, fabric filters, and/or scrubbers anyway in the reference case to comply with the state mercury policies.

2. MACT HCl Compliance

NEMS does not model HCl emissions from coal units. Indeed, HCl emission rates from individual units can vary significantly over time as the unit burns coal from different mines and seams with different chlorine contents. Since NEMS does not model HCl emissions from coal units and thus cannot determine which controls would be required for compliance with HCl policies, we developed rules to assign HCl control technologies to individual units based on review of technology assumptions in EPA's regulatory impact analysis (RIA) for the MACT proposal (EPA 2011f) and other analyses, including comments on the MACT proposal submitted to EPA from various organizations (in Docket No. EPA-HQ-OAR-2009-0234). We assumed that compliance with the HCl standard would be required by 2015.

We assumed that every coal unit would require either dry sorbent injection (DSI), a dry scrubber, or a wet scrubber to comply with the HCl standard. Note that the variability in HCl emission rate at individual coal units over time would tend to cause owners to make relatively conservative assumptions about compliance measures so that they do not exceed the standard when the chlorine content of their coal happens to be high. DSI has significantly lower capital costs than a dry scrubber, which in turn has lower capital costs than a wet scrubber (EPA 2011c).[2] Since NEMS does not include DSI among its set of emission control technologies, we could not directly apply DSI to coal units in NEMS. Instead, we assigned costs to units requiring DSI to represent installation of DSI.

We assumed that DSI would be installed for HCl compliance at unscrubbed units smaller than 300 MW that consume subbituminous coal. The size limit for DSI is the same as the Bipartisan Policy Center's assumption for its analysis of potential EPA regulations (BPC 2011, p. 24); the Edison Electric Institute made a similar assumption for one of its modeling scenarios by limiting DSI to units smaller than 200 MW (EEI 2011, p. 4). We assumed that dry scrubbers would be installed for HCl compliance at all unscrubbed and non-DSI units that consume Western bituminous coal, subbituminous coal, or lignite. We further assumed wet scrubbers would be installed for HCl compliance at all unscrubbed units that consume Eastern bituminous coal. DSI and dry scrubber installations would also require fabric filters.

As noted above, NEMS assumes that all new scrubbers are wet scrubbers (EIA 2011a, p. 46). Scrubber cost inputs for the Retirement Model, however, accurately reflect whether the unit would need to install a wet scrubber or dry scrubber (or DSI). Moreover, we modified the unit-specific cost inputs in NEMS so that units needing to install wet scrubbers, dry scrubbers, or DSI had the appropriate costs.

[2] Additional information on the costs of air emission control technologies appears at the end of this appendix.

3. MACT PM Compliance

NEMS does not model PM emissions from coal units and thus cannot determine which controls would be required for compliance with PM policies. The main control technologies for PM emissions are electrostatic precipitators (ESPs) and fabric filters (also called baghouses). NEMS includes fabric filters among its set of emission control technologies, but since NEMS does not model PM emissions, it only installs fabric filters on its own to reduce mercury emissions. We therefore developed rules to assign fabric filters to individual units based on reviews of technology assumptions in EPA's MACT RIA (EPA 2011f) and other analyses. We assumed that compliance with the PM standard would be required by 2015.

We assumed that most, but not all, coal units would require a fabric filter for PM compliance. Since NEMS installs fabric filters (in combination with ACI) on some coal units for compliance with state mercury policies and MACT mercury standards, these units would comply with the PM standard as well. We also required installation of fabric filters at units installing DSI or dry scrubbers for HCl compliance, and so these units too would comply with the PM standard. Thus, the only remaining coal units without fabric filters at this point are units with wet scrubbers (either existing wet scrubbers or new wet scrubbers for HCl compliance) and with sufficiently low mercury emission rates without fabric filters based on the NEMS parameters and determinations for mercury compliance. We reviewed EPA's MACT RIA data and assumed installation of fabric filters at the remaining coal units if they had fabric filters in the EPA data. The percentage of total U.S. coal capacity having fabric filters in our policy case is therefore approximately the same as the percentage in EPA's MACT RIA.[3]

Note that installing fabric filters at most U.S. coal units by 2015 is assumed to be feasible, despite the analysis by industry experts that such a large number of fabric filters could not be manufactured and installed in such a short period (UARG 2011).

D. Coal Combustion Residuals

EPA has considered several alternative forms of regulations in recent years for the disposal of coal combustion residuals (CCR), which include fly ash, bottom ash, boiler slag, and scrubber waste. The alternative forms of CCR regulations differ in their classification of CCR under Subtitles C or D of the Resource Conservation and Recovery Act (hazardous and non-hazardous, respectively) and compliance measures (for example, requiring liners at all surface impoundments or only at new surface impoundments). EPA proposed three alternative forms of CCR regulations in June 2010 (EPA 2010b). The unit-specific information in the RIA for this proposed rule, however, was based on a prior set of alternative forms that EPA developed in 2009 (EPA 2010c, p. 3).

Table A-5 summarizes our compliance assumptions for CCR regulations.

---

3 EPA (2011f, pp. 8-18 and 8-14) gives the total U.S. coal capacity in 2015 in the MACT scenario as 299 GW, and 243 GW have fabric filters. Thus, 81 percent of total U.S. coal capacity in 2015 would have fabric filters in EPA's MACT scenario.

Table A-5. Compliance Assumptions for CCR Regulations

Policy	Compliance Assumptions
CCR	Assign costs to units in 2015 based on EPA Subtitle D in initial proposal

Source: NERA assumptions as explained in text

We modeled CCR compliance costs at coal units in 2015 based on EPA's unit-specific information for the initial form of CCR regulation under Subtitle D of the Resource Conservation and Recovery Act (EPA 2010c, Exhibit J3). As noted above, EPA only provided unit-specific information for the initial set of alternatives it developed in 2009; EPA did not provide unit-specific information for the final set of alternatives that it proposed in 2010. The initial form of CCR regulation under Subtitle D would lead to a cost of $30 billion (present value in 2009 dollars).[4] Note that this cost lies near the middle of the range of cost estimates for CCR regulation. For example, EPA (2010b, p. 10) gives the cost of the final form of Subtitle C regulation as $20 billion, and EPRI (2010, p. 4-3) gives the cost of Subtitle C regulation as between $55 billion and $77 billion.

We used this unit-specific cost information from EPA (2010c, Exhibit J3) as the basis for the potential costs of CCR regulation.

E. Section 316(b)

EPA proposed alternative forms of regulations for cooling water intake under Section 316(b) of the Clean Water Act in April 2011 (EPA 2011g). The regulations would affect the design of cooling water intake structures (to reduce impingement of aquatic organisms against intake structures) and the flow rates through cooling water systems (to reduce entrainment of aquatic organisms into cooling water systems) at power plants and other large facilities. The alternative forms of 316(b) regulations differ in their requirements for intake structures and flow rates, including possible use of best professional judgment for determining best technology available on a site-specific basis.

Table A-6 summarizes our compliance assumptions for 316(b) regulations.

Table A-6. Compliance Assumptions for 316(b) Regulations

Policy	Compliance Assumptions
316(b)	Assign costs to units in 2015 based on EPA Option 1 for impingement and 46 facilities installing cooling tower retrofits for entrainment

Source: NERA assumptions as explained in text

4 EPA (2010b, Exhibit J3) gives the total annualized cost of the initial form of the Subtitle D alternative as $2.2 billion in 2009 dollars. EPA annualized these costs over 50 years. Using a real annual discount rate of 7 percent, this implies a present value of $30 billion.

We modeled 316(b) compliance costs for coal units in 2015 based on EPA information in the proposed rule related to Option 1, which includes a national requirement to reduce impingement, and an assumption that a total of 46 facilities would install cooling towers for entrainment under site-specific determinations. EPA (2011g, p. 22219) shows that Option 1 would lead to costs of $5 billion (present value in 2009 dollars) for electric generators to reduce impingement.[5] We estimated the apportionment of these costs across generation units, including coal units as well as natural gas, oil, and nuclear units, based on unit-specific cooling water intake data from EIA Form 860 (EIA 2011c).

EPA (2011g, p. 22211) noted that if the 46 fossil units with the largest cooling water withdrawals from tidal waters installed cooling towers to reduce entrainment, their total cost would be $7 billion.[6] Note that of the two hypothetical cooling tower scenarios for which EPA provided information, this scenario involved fewer facilities and lower total costs. We identified the 46 fossil units with the largest cooling water intake withdrawals from tidal waters using EIA Form 860 (EIA 2011c) and apportioned costs to individual units based on their intake data.

We used this unit-specific cost information based on EPA (2011g) as the basis for our modeling of the potential costs of 316(b) regulation.

F. Cost Assumptions for Air Emission Control Technologies

As discussed above, we relied on unit-specific inputs in NEMS for information about coal units for modeling retirements and energy market impacts. We modified the potential costs of air emission control technologies in NEMS to base them on EPA (2011c).

Table A-7 shows EPA and EIA assumptions for the costs of air emissions controls. These cost estimates include energy penalties for net capacity and heat rate due to some of the controls. Some types of costs show economies of scale (i.e., unit costs per kW are smaller for large units than small units), but other types of costs are uniform for all sizes of units. We used these cost assumptions from EPA in our modeling.

Note that the sudden large increase in demand for control technologies and skilled construction workers implied by our technology assumptions may not be feasible within the limited time assumed in our study and, in any event, the increased demand could drive up prices for control technologies. We did not develop any estimates of this “gold rush” effect. We assumed that the retrofits would be feasible on such a large scale and that there would be no price inflation due to the sudden increase in demand.

---

5 EPA (2011g, p. 22219) gives the total annualized cost of Option 1 for electric generators as $386 million in 2009 dollars. EPA annualized these costs over 50 years. Using a real annual discount rate of 7 percent, this implies a present value of $5 billion.

6 EPA (2011g, p. 22211) gives the total annualized cost of the 46 facilities installing cooling towers as $480 million in 2009 dollars. EPA annualized these costs over 50 years. Using a real annual discount rate of 7 percent, this implies a present value of $7 billion.

Table A-7. Air Emission Control Costs

	100 MW		300 MW		500 MW	
	EPA	EIA	EPA	EIA	EPA	EIA
Wet Scrubber						
Capital (2010$/kW)	$850	$762	$622	$580	$538	$485
Fixed O&M (2010$/kW-year)	$24.40	$24.99	$11.20	$24.99	$8.35	$24.99
Variable O&M (2010$/MWh)	$2.11	$0.44	$2.11	$0.44	$2.11	$0.44
Capacity Penalty	-1.84%	-5.00%	-1.84%	-5.00%	-1.84%	-5.00%
Heat Rate Penalty	1.87%	5.26%	1.87%	5.26%	1.87%	5.26%
Dry Scrubber						
Capital (2010$/kW)	$727	-	$532	-	$460	-
Fixed O&M (2010$/kW-year)	$17.71	-	$8.86	-	$6.76	-
Variable O&M (2010$/MWh)	$2.70	-	$2.70	-	$2.70	-
Capacity Penalty	-1.45%	-	-1.45%	-	-1.45%	-
Heat Rate Penalty	1.47%	-	1.47%	-	1.47%	-
SCR						
Capital (2010$/kW)	$268	$225	$217	$184	$201	$165
Fixed O&M (2010$/kW-year)	$2.60	$2.25	$0.83	$1.88	$0.73	$1.66
Variable O&M (2010$/MWh)	$1.38	$0.34	$1.38	$0.34	$1.38	$0.34
Capacity Penalty	-0.58%	0.00%	-0.58%	0.00%	-0.58%	0.00%
Heat Rate Penalty	0.59%	0.00%	0.59%	0.00%	0.59%	0.00%
ACI						
Capital (2010$/kW)	$30	$6	$12	$6	$8	$6
Fixed O&M (2010$/kW-year)	$0.12	$1.71	$0.05	$1.71	$0.03	$1.71
Variable O&M (2010$/MWh)	$0.52	$0.26	$0.56	$0.26	$0.60	$0.26
Capacity Penalty	-0.06%	0.00%	-0.06%	0.00%	-0.06%	0.00%
Heat Rate Penalty	0.06%	0.00%	0.06%	0.00%	0.06%	0.00%
Fabric Filter						
Capital (2010$/kW)	$230	$78	$187	$78	$170	$78
Fixed O&M (2010$/kW-year)	$0.94	$5.97	$0.83	$5.97	$0.73	$5.97
Variable O&M (2010$/MWh)	$0.16	$0.00	$0.16	$0.00	$0.16	$0.00
Capacity Penalty	-0.60%	0.00%	-0.60%	0.00%	-0.60%	0.00%
Heat Rate Penalty	0.60%	0.00%	0.60%	0.00%	0.60%	0.00%
DSI						
Capital (2010$/kW)	$134	-	$61	-	$43	-
Fixed O&M (2010$/kW-year)	$2.39	-	$0.94	-	$0.61	-
Variable O&M (2010$/MWh)	$7.70	-	$7.70	-	$7.70	-
Capacity Penalty	-0.79%	-	-0.79%	-	-0.79%	-
Heat Rate Penalty	0.79%	-	0.79%	-	0.79%	-

Note: "-" denotes that NEMS does not model the control technology.
Source: EPA (2011c) and NEMS inputs

G. References

Bipartisan Policy Center. 2011. *Environmental Regulation and Electric System Reliability*. Washington, D.C.: BPC, June. (www.bipartisanpolicy.org/sites/default/files/-BPC%20Electric%20System%20Reliability.pdf, accessed September 20, 2011)

Edison Electric Institute. 2011. *Potential Impacts of Environmental Regulation on the U.S. Generation Fleet*. Prepared by ICF International. Washington, D.C.: EEI, January (www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_

Plan/2011IRP/EEIModelingReportFinal-28January2011.pdf, accessed September 20, 2011)

Electric Power Research Institute. 2010. *Cost Analysis of Proposed National Regulation of Coal Combustion Residuals from the Electric Generating Industry*. Palo Alto, CA: EPRI, November.

U.S. Court of Appeals for the D.C. Circuit. 2008. *North Carolina v. EPA*. 550 F.3d 1176, 1178. Case 05-1244. Washington, D.C.: U.S. Court of Appeals for the D.C. Circuit, December 23. (www.epa.gov/airmarkets/progsregs/cair/docs/CAIRRemandOrder.pdf, accessed September 20, 2011)

U.S. Energy Information Administration. 2011a. *Annual Energy Outlook 2011*. Washington, D.C.: EIA, April. (www.eia.gov/forecasts/aeo/pdf/0383(2011).pdf, accessed September 20, 2011)

U.S. Energy Information Administration. 2011b. *Assumptions to the Annual Energy Outlook 2011*. Washington, D.C.: EIA, July. (www.eia.gov/forecasts/aeo/assumptions/pdf/-0554(2011).pdf, accessed September 20, 2011)

U.S. Energy Information Administration. 2011c. "Form 860 Data Files." www.eia.gov/cneaf/electricity/page/eia860.html, accessed September 20, 2011

U.S. Environmental Protection Agency. 2005. "Rule To Reduce Interstate Transport of Fine Particulate Matter and Ozone (Clean Air Interstate Rule); Revisions to Acid Rain Program; Revisions to the NO_x SIP Call; Final Rule." 70 *Federal Register* 25162-25405. Washington, D.C.: EPA, May 12. (edocket.access.gpo.gov/2005/pdf/05-5723.pdf, accessed September 20, 2011)

U.S. Environmental Protection Agency. 2010a. *Acid Rain and Related Programs: 2009 Highlights*. Washington, D.C.: EPA, December. (www.epa.gov/airmarkets/progress/ARP09_downloads/ARP_2009_Highlights.pdf, accessed September 20, 2011)

U.S. Environmental Protection Agency. 2010b. "Hazardous and Solid Waste Management System; Identification and Listing of Special Wastes; Disposal of Coal Combustion Residuals From Electric Utilities; Proposed Rule." 75 *Federal Register* 35128-35264. Washington, D.C.: EPA, June 21. (http://www.regulations.gov/#!documentDetail;-D=EPA-HQ-RCRA-2009-0640-0352, accessed September 20, 2011)

U.S. Environmental Protection Agency. 2010c. *Regulatory Impact Analysis for EPA's Proposed RCRA Regulation of Coal Combustion Residues Generated by the Electric Utility Industry: Appendix*. Washington, D.C.: EPA, April 30. (www.regulations.gov/-#!documentDetail;D=EPA-HQ-RCRA-2009-0640-0003, accessed September 20, 2011)

U.S. Environmental Protection Agency. 2011a. "Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals." 76 *Federal Register* 48208-48483. Washington, D.C.: EPA, August 8. (www.gpo.gov/fdsys/pkg/FR-2011-08-08/pdf/2011-17600.pdf, accessed September 20, 2011)

U.S. Environmental Protection Agency. 2011b. *Regulatory Impact Analysis for the Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone in 27 States; Correction of SIP Approvals for 22 States*. Washington, D.C.: EPA, June. (www.epa.gov/airtransport/pdfs/FinalRIA.pdf, accessed September 20, 2011)

U.S. Environmental Protection Agency. 2011c. *Documentation Supplement for EPA Base Case v4.10_PTox — Updates for Proposed Toxics Rule*. Washington, D.C.: EPA, March. (www.epa.gov/airmarkets/progsregs/epa-ipm/docs/suppdoc.pdf, accessed September 20, 2011)

U.S. Environmental Protection Agency. 2011d. "National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units; Proposed Rule." 76 *Federal Register* 24976. Washington, D.C.: EPA, May 3. (www.gpo.gov/fdsys/pkg/FR-2011-05-03/pdf/2011-7237.pdf, accessed September 20, 2011)

U.S. Environmental Protection Agency. 2011e. Letter from Gina McCarthy to Lee B. Zeugin. May 18. (www.4cleanair.org/Documents/EPAResponsetoLZeugin.pdf, accessed September 20, 2011)

U.S. Environmental Protection Agency. 2011f. *Regulatory Impact Analysis of the Proposed Toxics Rule*. Washington, D.C.: EPA, March. (http://www.epa.gov/ttnecas1/-regdata/RIAs/ToxicsRuleRIA.pdf, accessed September 20, 2011)

U.S. Environmental Protection Agency. 2011g. "National Pollutant Discharge Elimination System—Cooling Water Intake Structures at Existing Facilities and Phase I Facilities; Proposed Rule." 76 *Federal Register* 22174-22288. Washington, D.C.: EPA, April 20. (www.gpo.gov/fdsys/pkg/FR-2011-04-20/pdf/2011-8033.pdf, accessed September 20, 2011)

Utility Air Regulatory Group. 2011. *Feasibility of Retrofitting Fabric Filter Particulate Matter Control Technology to the Electric Generating Unit Inventory As Projected by EPA.* Report prepared by J. Edward Cichanowicz, Michael Hein, James Marchetti, and Walter Piulle. Washington, D.C.: UARG, August 4. (www.regulations.gov/#!documentDetail;-D=EPA-HQ-OAR-2009-0234-17785, accessed September 20, 2011)

Appendix B: Coal Unit Retirement Model

NERA has developed a retirement model to estimate the possible coal unit retirements due to the potential costs of EPA regulations. The model uses Monte Carlo uncertainty analysis to simulate the decision facing coal unit owners on whether to incur the costs to comply with additional future environmental requirements (and other future costs) or to retire the unit.

The sections below are organized as follows: Section A describes the main decision module, and Section B describes the sub-modules that generate the specific estimates used to run the Monte Carlo simulations in the main decision module.

A. Retirement Decision Module

The owner of each coal unit is presumed to base its decision on whether or not to retire the unit by comparing the future costs for the unit—taking into account potential additional environmental compliance costs as well as other costs—to the future costs of the likely alternative generation. The retirement decision module calculates the expected net present value (NPV) of costs for existing coal units as well as the NPV of costs for the likely alternative. Based upon likely future fuel market conditions, the alternative unit for comparison is assumed to be a combined cycle gas turbine (CCGT) unit. The cost calculations for coal and gas are done separately, but correlations in variables subject to uncertainty are taken into account. All retrofit costs are assumed to be incurred in 2015.

1. Net Present Value of Costs for Existing Coal Units

The NPV of costs for existing coal unit *i* is given by the following expression:

Equation 1. NPV of existing coal costs

$$d_{ir} R_i + \sum_{t=1}^{T_i} d_{it} (C_{it} + O_{it} + E_{it})$$

Where:

- R_i is the capital cost of retrofits. The total cost of retrofits for a given plant depends on the plant's current configuration, the randomly drawn retrofit costs for that plant from the retrofit/construction cost module, and what regulatory requirements the plant has in the regulatory scenario of interest. The cost of retrofits is then just the sum of the costs for each individual retrofit technology required at the plant.

- d_{ir} is the discount rate for unit i in year r, where r is the year in which retrofits take place. It is given by:

$$\left(\frac{1}{1+r}\right)^{t-1}$$

where t indicates time in years, where the first year in the model is t=1. The discount rate for a given unit depends on whether the utility that owns the unit is private or public. Following the NEMS model, we take the mean of the (real) discount rate to be 7 percent for units owned by public power organizations (e.g., the Tennessee Valley Authority and rural electric cooperatives) and 11.8 percent for units owned by private (investor-owned) companies, including units owned by regulated utilities with private (investor-owned) parent companies.

- d_{it} is the discount rate for unit i in year t, defined as above for d_{ir}.

- T_i is the remaining lifetime of unit i in years.

- C_{it} is the cost of coal for unit i in year t. The cost of coal is calculated by the hourly operation module when run decisions are calculated. It is essentially the average cost of coal across all operating hours weighted by the capacity factor at each hour. These plant-specific costs are developed as described in the coal cost module section. For the small number of plants with missing coal costs, average regional costs are used. If a retrofit increases the plant heat rate it will increase coal costs.

- O_{it} is the operating and maintenance (O&M) cost for unit i in year t. This is calculated as the sum of variable O&M and fixed O&M. Some retrofits result in additional O&M costs; where this is the case, variable O&M and/or fixed O&M are increased accordingly. We use EPA's O&M cost assumptions from the MACT analysis. Variable O&M costs for a year are calculated as the sum of hourly variable O&M costs. If we take V_{ih} to be the variable O&M costs for unit i in hour h (in dollars per megawatt-hour), then V_{it}, the variable O&M costs for unit i in year t, are given by:
$$\sum_{h=1}^{8760} TC_i (L_{ih} \cdot V_{ih})$$
where TC_i is the total capacity for plant i and L_{ih} is the capacity factor for plant i in hour h.

- E_{it} is the cost of system energy for unit i in year t necessary to compensate for capacity factors less than one at any hour. In order to make an appropriate comparison between existing coal and new gas, the costs of both gas and coal in our model are calculated as the costs to generate TC_i times 8760 energy per year. This assures that the retirement decision accounts for differences in the capacity factors of new and existing units. Thus, included in the calculation of the costs of existing coal is the cost of system energy necessary to compensate for capacity factors less than one at any hour. E_{it} is calculated as:
$$PM_{it} \cdot PE_{it} \cdot G_{it}$$
Here, G_{it} is the generation by unit i in year t, PM_{it} is the ratio of the weighted average system energy cost to the overall average electricity price across all simulation draws at the power hub to which plant i is assigned ($WASC_{ijt}/ASEC_{it}$), and PE_{it} is the average marginal cost of energy in the NERC region to which i belongs in year t (from the NEMS model outputs). The value of G_{it} is an output of the hourly operation module and is calculated as:
$$G_{it} = \sum_{h=1}^{8760} TC_i (L_{ih})$$
The weighted average system energy cost is calculated as:

$$WASC_{ijt} = \frac{\sum_{h=1}^{8760}(1-L_{ijh})P_{ijh}}{\sum_{h=1}^{8760}L_{ijh}}$$

whereas the overall average system energy cost is:

$$ASEC_{it} = \frac{1}{8760}\cdot\frac{1}{100}\cdot\sum_{j=1}^{100}\sum_{h=1}^{8760}P_{ijh}$$

where P_h is the marginal cost of energy at hour h from the electricity price module. Thus, the factor of $PM_{it}\cdot PE_{it}$ in the calculation of E_{it} serves to calibrate the outputs of the electricity price and hourly operation modules to NEMS electricity prices and map the five power hubs to the twenty-two NERC regions.

2. Net Present Value of Costs for Potential Alternative Unit (New CCGT)

The NPV of costs for replacing existing coal unit i with new CCGT of equal capacity is calculated as:

Equation 2. NPV of replacement CCGT costs

$$\sum_{t=1}^{T_i} d_{it}(CG_{it}+OG_{it}+EG_{it}+ON_{it})$$

Where d_{it} and T_i are identical to that for existing coal, and:

- CG_{it} is the average delivered cost of gas for the region in which unit i is located in year t using the appropriate capacity factor and heat rate.

- OG_{it} is the total O&M costs in year t for a CCGT constructed to replace unit i. This incorporates both fixed and variable O&M costs. The variable O&M costs are a function of the hourly capacity factors for a new CCGT in year t. These capacity factors are modeled based on the predicted operation of a sample of recently constructed CCGTs in each region and are an output of the hourly operation module. Thus, there are actually several calculations of replacement CCGT costs to compare to each coal plant, one for each CCGT in the sample of recently constructed CCGTs in each region.

- EG_{it} is the cost of grid energy to bring total generation to TC_i times 8760. This is calculated in the same way as the cost of grid energy for coal plants.

- ON_{it} is the equivalent annual overnight capital cost payment in year t for a CCGT replacement for plant i. The overnight costs are always annualized over the entire lifetime of the gas plant (30 years, consistent with the NEMS model), and are based on the sampled CCGT overnight costs drawn in the retrofit/construction cost module. However, since T_i may be less than 30 (and the modeling horizon only encompasses 25 years), the entire capital cost of the plant is not reflected in this calculation. This avoids inappropriately overstating the equivalent annual cost of a CCGT plant built to replace an existing coal plant.

3. Monte Carlo Retirement Decision Calculation

The NPV of costs for existing coal and for replacement CCGT are compared in each of the 100 simulation draws used in the Monte Carlo formulation. The costs for CCGT are based on the minimum of costs calculated using the sampled recently constructed CCGTs in each region as the basis for hourly operation of a new CCGT. Since a new CCGT would be at least as efficient as any existing CCGTs, this calculation is conservative (in the sense that it might overstate the future costs of a future CCGT and thus understate the likelihood of retirement).

The owner is presumed to retire the coal unit based upon a comparison of the NPV of the costs of the coal unit and the costs of the replacement CCGT plant. In particular, the retirement decision sub-module calculates the difference in costs for each of the 100 equally-likely Monte Carlo draws. The coal unit is presumed to retire if the expected value of this cost difference is positive, i.e., the coal unit is expected to be more expensive than the replacement natural gas unit.

B. Individual Cost Component Sub-Modules.

The Retirement Model includes separate sub-modules to model the various elements that influence the cost of continuing to operate an existing coal unit and the cost of replacing the exiting coal unit with a new combined cycle gas turbine (CCGT) unit. The methodology in each sub-module for energy prices results in mean values based upon the NEMS model using AEO 2011, with the sub-modules focusing on developing estimates of the potential alternative price paths. These sub-modules are summarized and described below.

1. *Natural gas price simulation sub-module*. This sub-module simulates possible future natural gas price paths. The formulation assumes that future natural gas prices can be modeled as an autoregressive process.

2. *Coal price sub-module*. This sub-module models regional coal prices. The formulation assumes that future coal prices can be modeled as a vector autoregression (VAR) process. Coal prices in several regions are modeled as dependent time series.

3. *Electricity price sub-module*. This sub-module models hourly electricity prices. The empirical formulations are based upon data from five major trading hubs across the United States.

4. *Hourly power plant operation sub-module*. This sub-module models the hourly operation of existing coal plants greater than 25 megawatts (MW) capacity. The sub-module also models operation of CCGT units in each region on the basis of recently constructed units.

5. *Retrofit and construction costs sub-module*. This sub-module models retrofit costs for emission control technologies and construction costs for new CCGT units as random variables, with the construction parameters assumed to be correlated. (Costs for the same type of control at different plants are assumed to be more highly correlated than costs for different controls and for controls and new construction costs.) The parameters for the model are taken from EPA cost assumptions for the MACT analysis and recent engineering reports.

The following sections provide additional information on these sub-modules.

1. Natural Gas Price Simulation Sub-Module

The natural gas price module models natural gas prices as an autoregressive process of order one (AR-1 process). The model for price at time ***t*** is:

Equation 3. Natural gas price model

$$\log(p_t) = a + g\log(p_{t-1}) + e_t, \quad e_t \sim N(0, s^2)$$

The parameters of the model are a constant term (a), an autoregressive term (g), and a random error term (e_t), which is assumed to be normally distributed with zero mean and unknown variance (s^2). The parameters are estimated from daily Henry Hub price data for the years 2005-2010. The estimated value of the autoregressive term is less than one, and therefore the model for gas price is mean-reverting.

Using the estimated parameter values, we then simulate 100 future daily natural gas price paths from 2011-2035 for use in the model. Simulation is relatively simple: starting from the last day's price in the historical data, simulate the first day of the forecast series by taking the log of the previous day's price, multiplying by the estimated value of g, adding the estimated value of a, and adding a value drawn from N(0, s^2). This is repeated for the second day of the forecast using the simulated value from the first day, and so on until prices have been simulated through the end of 2035. This entire process is then repeated 100 times to give 100 daily price paths through 2035.

As noted above, we adjust the simulated natural gas price paths such that the expected gas price in each year matched the EIA forecast. The expression for the price at time ***t*** in our model is given by:

Equation 4. Expression for price in the natural gas model

$$p_t = \exp(a + e_t)p_{t-1}^{g}$$

From this we have that the expression for the expected price at time ***t***, given the price in the previous period, is:

Equation 5. Expression for expected value of price in period *t* given price in period *t-1*.

$$E(p_t \mid p_{t-1}) = \exp\left(a + s^2/2\right)p_{t-1}^{g}$$

From this expression it is clear that any constant C added to the right hand side of the original log-log form of the model will result in the conditional expectation of p_t being multiplied by exp(C). Thus, we simulate many price paths and take the mean price in each year (which is a consistent estimator of the expectation of price in any year). We then add a constant C_y to the right hand side of Equation 3 for every day in year y such that the expected price in year y

matches the NEMS price in year *y*. We then simulate 100 price paths from this calibrated form of the model.

2. Coal Price Sub-Module

The variability in coal prices is modeled using information for the two main coal contracts for bituminous and sub-bituminous coal (Central Appalachian/Big Sandy and Powder River Basin (PRB), respectively) using a vector autoregression (VAR). (Lignite coal variability is assumed to be the same as sub-bituminous.) The model assumes that coal prices are a stochastic process and that prices in the two regions are related. The mathematical form of the model is:

Equation 6. Coal price model

$$Y_t = c + AY_{t-1} + e_t, \quad e_{\mathrm{t}} \sim N_2(0, \Sigma)$$

Where Y_t is a 2x1 vector of prices (the Appalachian and PRB prices at time t), A is a linear transformation of the lagged price Y_{t-1}, c is a 2x1 vector of constants, and ε_t is a bivariate normal random variable with a 2x1 mean vector of zeroes and covariance matrix Σ. We use historical weekly coal price data from 2005-2010 to estimate the parameters of the model (c, A, and Σ).

We then simulate from this model 100 weekly price paths for 2011-2035 for PRB and Appalachian coal. As noted, the modeling assures that the mean prices are equal to those predicted in NEMS; we calculate the ratio of the average price in each year for each of the two coal contracts in our forecast to the average price from 2005-2010. We then add constants to the expression in equation 4 to make the ratios of the annual average price to the 2005-2010 average the same as the ratio of the annual mine mouth prices for bituminous and subbituminous coal in NEMS to the average prices for those coals from 2005-2010. Thus, the VAR model gives us the dependence structure and uncertainty in coal prices, whereas NEMS provides the means.

We then take a two-year moving average of the simulated coal prices in each of the 100 simulations and then take the ratio of this moving average to the overall average coal price for each year (across all simulations). We use the plant-specific average fuel costs from EIA 423 for 2005-2010 and multiply them by the ratio of the moving average from each of the 100 simulations to the overall moving average to get plant-specific coal prices for each week in the model. We use a long-term moving average to reflect that most coal prices for electric utilities are set by long-term contracts and an analysis of historical market prices compared to historical coal costs for electric utilities showed that a two-year moving average was a good predictor of relative coal price movements.

A small number of plants are missing cost data for delivered coal in EIA 423. We impute costs for delivered coal based on the quantity and type of coal delivered to each plant using an inverse-distance weighted average of the costs of the same type of coal delivered to nearby plants. We verified that the historical average delivered prices for the 22 NERC regions in the NEMS model calculated from EIA 423 (and using the above methodology to fill in missing prices) were very similar to NEMS average prices for the years 2005-2010 for those regions. The EIA data provides monthly coal costs; for consistency with the run decision model, we linearly interpolate between the monthly costs to obtain daily coal costs.

3. Electricity Price Sub-Module

The variability in hourly electricity prices is modeled using data for five hubs throughout the United States (ERCOT, PJM, Cinergy, SP15, and NYISO). Electricity prices are taken to be a function of the previous hour's electricity price, natural gas prices (with the magnitude of the effect varying with the hour), hour of day, season, whether the day is a weekend day or a weekday, and an innovation (error) term. The innovations are normal with zero mean and stochastic, time-varying variance. The mathematical specification is an exponential GARCH (EGARCH) model and is given by the following set of equations:

Equation 7. Electricity price model

$$\log(p_t) = X_t b + a \log(p_{t-1}) + e_t$$

$$e_t = s_t z_t \quad \mathrm{z_t} \sim N(0,1)$$

$$\log(s_t^2) = w + g_g g(Z_{t-1}) + g_s \log(s_{t-1}^2)$$

$$g(Z_t) = qZ_t + l\left(|Z_t| - E\left(|Z_t|\right)\right)$$

Where p_t is the price at time *t,* and *X* is a matrix of covariates. The structure of the model allows the sign and magnitude of the standard normal random variable Z_t to affect volatility (σ^2) separately. The model also allows for heteroskedasticity (through the dependence of s_t^2 on s_{t-1}^2) and volatility clustering (periods of large price swings and periods of relative calm).

The covariates in the mean regression (the matrix X_t) include dummy variables for hour of day, hour of day dummies interacted with natural gas prices, seasonal dummies, and weekday/weekend dummies. The model parameters are estimated on historical electricity price data for the five electricity price hubs for 2005-2010. We then simulate electricity price series for each of the five hubs from the model, using as inputs the simulated natural gas prices from the natural gas price model. We simulate 100 realizations of hourly prices for 2011-2015.

4. Hourly Power Plant Operation Sub-Module

The hourly power plant operation module models power plant hourly run decisions and output as a function of price and marginal costs. The relevant price variability in the model is determined by matching each power plant to one of the five regional hubs. As noted, the mean electricity prices are based upon NEMS AEO 2011.

The decision of whether to operate is modeled as a logistic regression:

Equation 8. Run decision model

$$r_t \sim bernoulli(p_t)$$

$$p_t = \Pr(r_t = 1) = \frac{e^{X_t b}}{1 + e^{X_t b}}$$

Where $r_t = 1$ indicates that the plant decides to run at time t. Here X_t is a vector of covariates, which in this case are constant, the hourly electricity price, and negative one times the sum of fuel costs and allowance costs per MWh for the plant at each hour. In the case of CCGT plants, the implied heat rate (ratio of the electricity price to the gas price) is used in place of the electricity price less costs.

Conditional on operating, we then model the capacity factor (output divided by capacity) as a mixture of linear regression models. In this model, each unit can operate in up to five distinct “modes,” and the choice of “mode” is a function of the electricity price less costs (or, in the case of CCGT, the implied heat rate) and a constant specific to each mode. Conditional on choosing a “mode,” the capacity factor is modeled as normally distributed with mean and variance estimated from the data. The mathematical representation of the model is:

Equation 9. Capacity factor model

$$m_t \mid r_t = 1 \sim multinomial(1, s_t)$$

$$s_{jt} = \Pr(m_t = j \mid r_t = 1) = \frac{e^{X_t b_j}}{\sum_{i \neq j} e^{X_t b_i}} \quad b_1 = \overset{\mathbf{r}}{0}$$

$$L_t \mid m_t = j, r_t = 1 \sim N(m, s^2)$$

Where m_t is the operating mode at time t (m_t=1,…,5), s_t is a simplex vector (vector whose components add to one, making them plausible as probabilities for different alternatives), X_t is a matrix of covariates (here covariates are the electricity price less costs for coal plants or implied heat rate for CCGT and a dummy for the operating “mode” alternative), L_t is the capacity factor at time t and μ and σ^2 are the mean and variance of a normal distribution. The choice of this form for the model was based on the observation that power plant capacity factors exhibit multimodality, whereas electricity prices, the main factor in power plant operation decisions, do not. Thus, some type of model allowing for flexible multimodality was necessary, and the mixture of normal models is one such model that has well-established estimation techniques available.

We estimate the model on historical hourly power plant operation data for coal plants and a sample of recently constructed CCGTs for the years 2005-2010. The model predicts the historical capacity factors very accurately, with virtually all of the variance in the historical data explained by the model. We then simulate power plant operation for coal plants and sampled CCGTs using the simulated electricity, coal, and gas prices from the electricity and gas price modules for the years 2011-2035, as well as estimates of incremental variable cost of new controls, expected allowance prices, and heat rate penalties of new controls as factors affecting coal plant marginal costs. The result is 100 sets of hourly plant operation patterns for every plant in the dataset.

5. Retrofit Costs and Construction Costs Sub-Module

This sub-module develops information on the variability in technology retrofit costs as well as CCGT construction costs, which are assumed to be correlated in our model. We model the variability in costs for the relevant control technologies (wet and dry scrubbers, dry sorbent injection, fabric filters, activated carbon injection, closed cycle cooling, and coal combustion residual compliance costs) and for new CCGTs. The correlations include those for different technologies and the same plant, for the same technology across plants, and for retrofit costs and new construction costs. The vector of all control costs is modeled as multivariate lognormal, mathematically represented as:

Equation 10. Retrofit/control costs model

$$r \sim N(m, \Sigma)$$

$$c = e^{r}$$

Where r is a multivariate normal random variable with mean vector μ and covariance matrix Σ, and c is the control/construction cost vector (a vector containing all control/construction costs for all plants). There exists a closed-form expression for the expected value of c as a function of μ. We take the EPA's control costs estimates for different control types and EIA's overnight costs for CCGT as the expected value of c, and back solve for the mean vector μ. No suitable data exists to estimate the covariance matrix Σ. Thus, we create a covariance matrix from a correlation matrix with the following assumed structure. We assume that the correlation between costs for the same control at different plants is 0.6 and the correlation between costs for different controls at different plants is 0.4. We assume that the correlation between costs for all environmental controls and the capital cost of a new CCGT is 0.4. Thus, we assume that costs for the same type of control will be more highly correlated than costs for different types of controls.

In order to create a covariance matrix from this correlation matrix, we also must define a variance vector for the control/construction costs (a vector containing the variances for each control type/plant combination and for CCGT retrofit costs). As described previously for the mean vector, there is a closed-form expression for the variance vector of the normal distribution in terms of the variance vector of the lognormal distribution. Variances are based on the uncertainty ranges given in the Raytheon Coal Unit Environmental Cost Model documentation (which is used by EIA to estimate plant retrofit costs in the NEMS model). In the Raytheon documentation, retrofit costs estimates are given with an uncertainty of ±30%. We assume that standard deviations of the lognormal cost distributions are 15% of the cost, or half of the uncertainty range given by the Raytheon report.

The model takes 100 separate draws of retrofit/construction costs from the multivariate lognormal distribution defined above. The joint variability in costs for retrofits and for new CCGT construction is then used in the retirement decision sub-module, as discussed above.

Appendix C: Energy Market Modeling

This appendix provides details on the National Energy Modeling System (NEMS) as well as our data and methodology for using NEMS to model the potential energy market impacts of the four EPA regulations. This appendix also shows key energy market impact results from NEMS for each year between 2012 and 2020.

A. National Energy Modeling System

This section provides an overview of NEMS and its input categories related to emission controls.

1. Overview

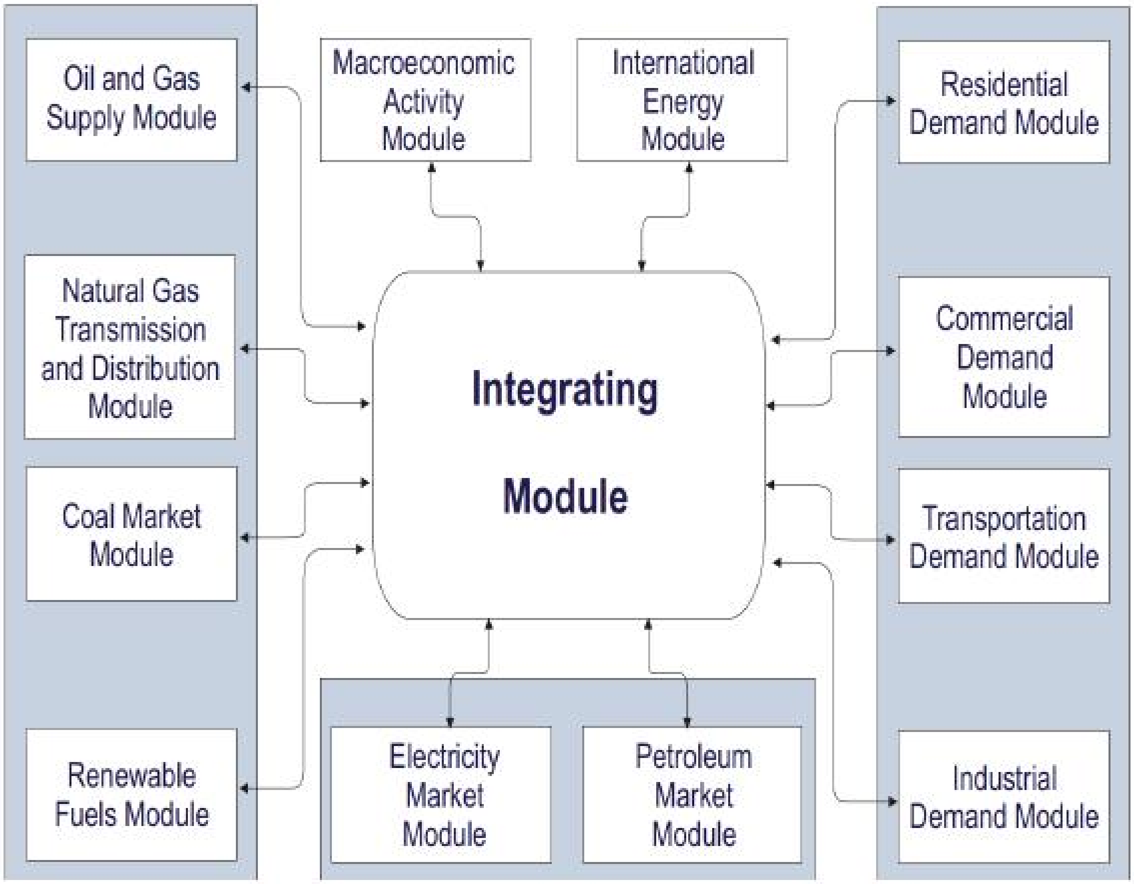
The U.S. Energy Information Administration (EIA) developed and maintains NEMS to produce projections of energy prices and quantities in the long term. EIA also uses NEMS to perform policy analyses in response to requests from Congress, the White House, the Department of Energy, and other government agencies. EIA prepares an *Annual Energy Outlook* (*AEO*) with long-term projections of energy prices and quantities based on current policies and various assumptions. As discussed in Appendix A, our modeling of the potential energy market impacts of the four EPA regulations with NEMS is based on inputs for *AEO 2011* (EIA 2011a); its assumptions are summarized in EIA (2011b).

Figure C-1 shows the thirteen modules in NEMS and their linkages. All modules interact via the Integrating Module at the center of the figure. The four modules to the left in the figure (Oil and Gas Supply, Natural Gas Transmission and Distribution, Coal Market, and Renewable Fuels) relate to the supply of primary energy sources. The four modules to the right in the figure (Residential Demand, Commercial Demand, Transportation Demand, and Industrial Demand) relate to the demand for energy. The two modules to the bottom of the figure (Electricity Market and Petroleum Market) convert primary energy sources into electricity and petroleum products. Finally, the two modules to the top of the figure (Macroeconomic Activity and International Energy) provide information from outside U.S. energy systems.

NEMS uses the thirteen modules shown in Figure C-1 to balance energy supply and demand in each region of the United States. In particular, the model calculates the least-cost way to satisfy demand in each region based on the costs of alternative forms of energy and various constraints, including resource availability and energy transportation infrastructure. The level of regional detail in NEMS varies for different forms of energy. For example, NEMS divides the United States into 22 electricity markets, 13 coal production regions, and nine natural gas production regions. Regional detail for energy demand is based on the nine Census divisions.

Additional detail on energy market modeling and NEMS can be found in EIA (2009) and EIA (2011b).

Figure C-1. Overview of NEMS



Source: EIA (2011b, p. 4)

2. Input Categories Related to Emission Controls

NEMS input files include a database of all generation units in the United States as well as parameters that apply uniformly to all units within certain categories. The database includes current and planned scrubber, SCR, and particulate controls for each coal unit in the United States. The database also includes information on some types of environmental control costs for each coal unit. Other types of environmental control costs enter NEMS as parameters that apply uniformly to the relevant coal units.

Table C-1 summarizes unit-specific and uniform inputs related to emission controls. Note that direct sorbent injection (DSI) is not included as an emission control in NEMS, as discussed in Appendix A.

Table C-1. NEMS Inputs Related to Emission Controls

	Miscellaneous	Scrubbers	SCR	ACI	FF	DSI
Unit-specific inputs	- Construction date - Retirement date - Capacity - Capacity factor (historical) - Heat rate - Baseline fixed O&M cost (excluding controls) - Baseline variable O&M cost (excluding controls) - Baseline annual capital cost (excluding controls)	- Current or planned configuration - Capital cost ($/kW) - Emission reduction percentage	- Current or planned configuration - Capital cost ($/kW) - Additional fixed O&M cost - Additional variable O&M cost - Emission reduction percentage	- Current or planned configuration - Emission reduction percentage (based on other controls and coal type)	- Current or planned configuration - Emission reduction percentage (based on other controls and coal type)	- Not in NEMS
Uniform inputs for all coal units		- Capacity penalty - Heat rate penalty - Additional fixed O&M cost - Additional variable O&M cost		- Capital cost ($/kW) - Additional fixed O&M cost - Additional variable O&M cost	- Capital cost ($/kW) - Additional fixed O&M cost	- Not in NEMS

Source: NERA review of NEMS inputs

3. Input Categories Related to CCR and 316(b)

NEMS does not model compliance with CCR or 316(b) policies. As discussed further below, we modeled these policies in NEMS by adding their costs to the unit-specific inputs for general capital costs.

B. Methodology

This section describes NEMS inputs and outputs for modeling the potential energy market impacts of the four EPA regulations.

1. NEMS Inputs

We entered three types of modeling inputs into NEMS: (1) potential emission control costs; (2) coal unit retirements; and (3) compliance measures. This section describes each of these types of inputs.

a. Emission Control Costs

As described in Appendix A, we used EPA estimates for potential emission control costs rather than the EIA assumptions built into NEMS. As summarized above in Table C-1, NEMS incorporates data on the potential costs of environmental controls in case installation of such controls is required. We modified these emission control costs in NEMS for both the reference case and policy case so that costs would consistently reflect EPA cost estimates in both cases. For example, the reference case includes state mercury regulations that would cause some coal units to install ACI and fabric filters. The costs of these ACI and fabric filter retrofits in the reference case reflect EPA cost assumptions, just as they do in the policy case.

To achieve the maximum level of unit-level detail on costs and compliance measures, we used the unit-specific inputs shown in Table C-1 to the maximum extent possible. For emission control costs without unit-specific inputs in NEMS, we used uniform inputs for all units. As shown above in Table C-1, NEMS has unit-specific inputs for scrubber capital costs and SCR capital and O&M costs, so we modified these unit-specific inputs to reflect EPA cost assumptions. Since NEMS only has uniform inputs for scrubber O&M costs and ACI and FF costs, we modified those uniform inputs to reflect EPA cost assumptions. Since NEMS does not model DSI, the variable O&M cost of FF, or the heat rate and capacity penalties of any emissions controls other than scrubbers, we adjusted the relevant unit parameters manually in the unit database. Our modifications for emission control costs are shown below in Table C-2.

Table C-2. Modification of NEMS Emission Control Costs

	Scrubbers	**SCR**	**ACI**	**FF**	**DSI**
Capital	Assign by unit using NEMS scrubber capital cost input variable	Assign by unit using NEMS SCR capital cost input variable	Assign uniform cost to all units	Assign uniform cost to all units	Assign by unit using NEMS general capital cost input variable
Fixed O&M	Assign uniform cost to all units	Assign by unit using NEMS SCR fixed O&M cost input variable	Assign uniform cost to all units	Assign uniform cost to all units	Assign by unit using NEMS general fixed O&M cost input variable
Variable O&M	Assign uniform cost to all units	Assign by unit using NEMS SCR variable O&M cost input variable	Assign uniform cost to all units	Assign by unit using NEMS general variable O&M cost input variable	Assign by unit using NEMS general variable O&M cost input variable
Heat Rate Penalty	Assign uniform penalty to all units	Assign by unit using NEMS heat rate input variable	Assign by unit using NEMS heat rate input variable	Assign by unit using NEMS heat rate input variable	Assign by unit using NEMS heat rate input variable
Capacity Penalty	Assign uniform penalty to all units	Assign by unit using NEMS capacity input variable	Assign by unit using NEMS capacity input variable	Assign by unit using NEMS capacity input variable	Assign by unit using NEMS capacity input variable

Source: NERA

b. Coal Unit Retirements

As described in Appendix B, we used the Retirement Model to determine which coal units would likely retire rather than incur costs for the four EPA regulations. We also used the Retirement Model for the reference case to determine which coal units would likely retire even in the absence of the four EPA regulations. We entered these retirements into the NEMS database of generation units for the end of 2014 (immediately before compliance with MACT, CCR, and 316(b) is assumed to be required in 2015). We did not allow NEMS to retire coal units based on its own economic evaluations in either the reference case or the policy case.[1]

c. Compliance Measures

The compliance measures that we modeled for CSAPR, MACT, CCR, and 316(b) for the policy case are described in Appendix A. That appendix also describes our modeling of compliance measures for the two most relevant environmental policies in the reference case: CAIR and state mercury regulations. Our methodology and assumptions are summarized briefly here.

We modeled CAIR in the reference case by setting regional emission caps through 2011 in NEMS and allowing NEMS to determine which coal units would need to install environmental controls or fuel switch to lower their SO_2 and NO_x emissions. We modeled state mercury regulations in the reference case by requiring mercury reductions in specific regions in NEMS based on the locations of states with mercury regulations and allowed NEMS to determine which coal units would need to install ACI, fabric filters, and/or scrubbers to comply.

For the policy case, we modeled CSAPR by setting regional caps in NEMS and allowing NEMS to determine which additional coal units would need to install environmental controls or fuel switch to lower their SO_2 and NO_x emissions beyond reductions for CAIR (or for caps without CAIR from 2012 onward). We modeled the MACT mercury standards by requiring mercury reductions based on the standards shown in Appendix A and allowing NEMS to determine which coal units would need to install ACI, fabric filters, and/or scrubbers to comply. We modeled the MACT HCl and PM standards by requiring scrubbers, DSI, and/or fabric filters at particular units, as discussed in detail in Appendix A. Finally, we modeled the CCR and 316(b) regulations in NEMS by applying their unit-specific costs in the NEMS database of generation units using the input variable for general capital costs, since NEMS does not model compliance with non-air emission regulations such as the CCR and 316(b) regulations.

---

1 The NEMS model provides less detailed modeling of coal unit retirements than provided for in the retirement model we used. With regard to dispatch, NEMS provides for 216 distinct periods (summer, winter, spring and fall by peak, off-peak and weekend). As with other retirement models (see, e.g., Brattle Group 2010), our retirement model models the full 8,760 hours per year of electricity prices and thus allows for more precise dispatch modeling and forecasts of costs for existing and potential new units. Our model also incorporates uncertainties in key energy price and cost variables and allows the retirement decision to depend upon these uncertainties.

2. NEMS Outputs

Based on the coal unit retirements and the costs of the compliance measures, NEMS calculated the cost-minimizing set of energy prices and quantities. NEMS also endogenously determined the new generation capacity necessary in each electricity region to replace the coal units that would retire. The electricity price results from NEMS include the costs of compliance measures as well as the costs for new generation capacity, among other electricity price components.

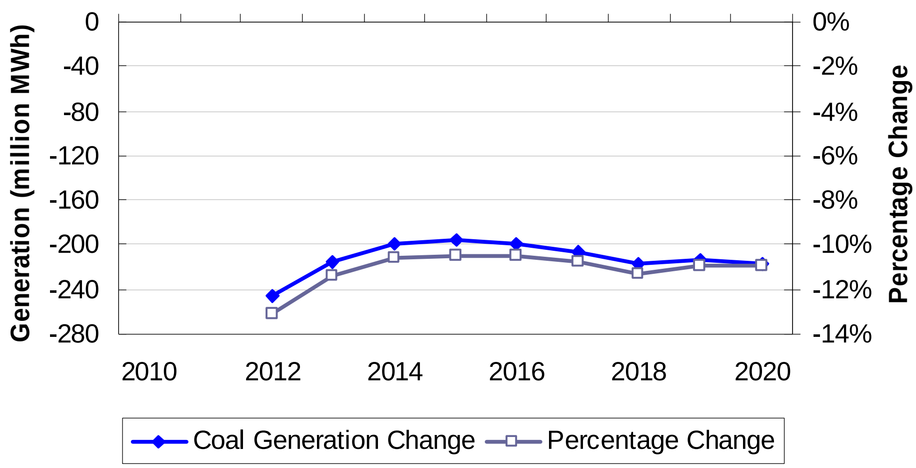
C. Results

This section shows key energy market impact results from NEMS due to the four EPA regulations for each year between 2012 and 2020.

1. Coal-Fired Generation

Figure C-2 shows the change in coal-fired generation between 2012 and 2020 due to the four EPA regulations relative to reference case projections. Coal-fired generation decreases because of the coal unit retirements and the additional costs borne by coal units that do not retire (which make the units less competitive in electricity markets and thus lower their capacity factors). Note that coal units incur costs for their SO_2 and NO_x emissions in the policy case beginning in 2012 due to the introduction of the trading program for CSAPR, with CAIR assumed not to be in place after 2011. In 2015, when many coal units install scrubbers and DSI for MACT HCl compliance, their SO_2 emissions decrease and allowance prices decrease to zero. As a result, coal units have lower costs for SO_2 emissions from 2015 onward than they had from 2012 to 2014. This tends to raise their capacity factors relative to their levels from 2012 to 2014. Coal unit retirements contribute to lower coal-fired generation from 2015 onward.

Figure C-2. Change in Coal-Fired Generation Relative to Reference Case

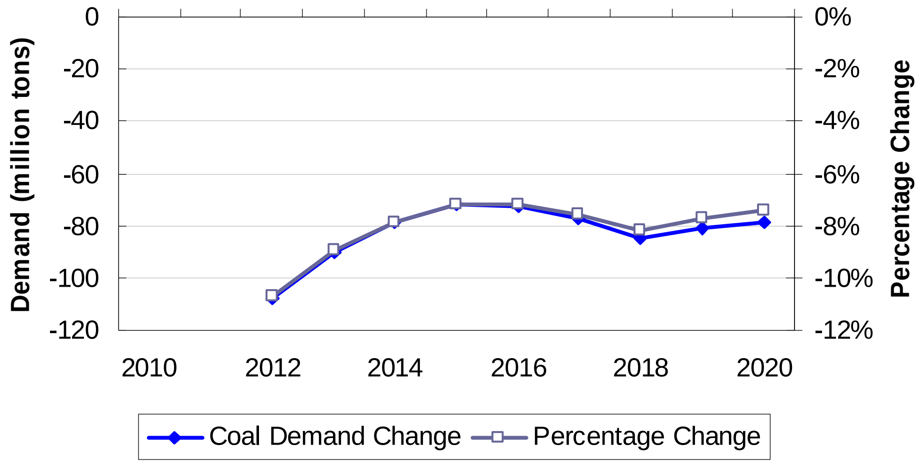


Note: Coal-fired generation in 2010 was 1800 million MWh (EIA 2011a).
Source: NERA calculations as explained in text

2. Electricity Sector Coal Demand

Figure C-3 shows the change in electricity sector coal demand between 2012 and 2020 due to the four EPA regulations relative to reference case projections. Just as for coal-fired generation, electricity sector coal demand decreases because of the coal unit retirements and the additional costs borne by coal units that do not retire (which make the units less competitive in electricity markets and thus lower their capacity factors). The percentage change in electricity sector coal demand is similar to the percentage change in coal-fired generation; the small difference between the percentage changes reflects shifts in the average heat content of coal consumed by units.

Figure C-3. Change in Electricity Sector Coal Demand Relative to Reference Case

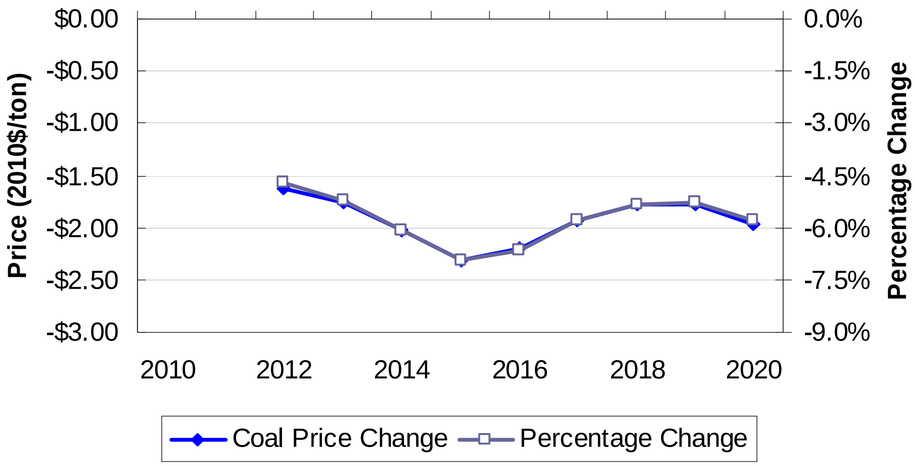


Note: Electricity sector coal demand in 2010 was 1000 million tons (EIA 2011a).
Source: NERA calculations as explained in text

3. Coal Price

Figure C-4 shows the change in average coal minemouth (i.e., wholesale) price between 2012 and 2020 due to the four EPA regulations relative to reference case projections. The price of coal would decrease because of reduced demand for coal by the electricity sector.

Figure C-4. Change in Average Coal Minemouth Price Relative to Reference Case

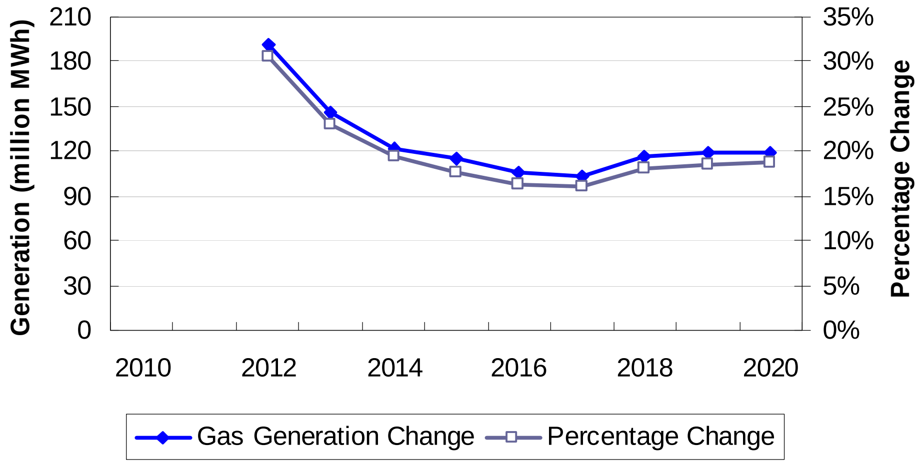


Note: Average coal minemouth price in 2010 was $37/ton (2010$) (EIA 2011a).
Source: NERA calculations as explained in text

4. Natural Gas-Fired Generation

Figure C-5 shows the change in natural gas-fired generation between 2012 and 2020 due to the four EPA regulations relative to reference case projections. When coal units retire and capacity factors for the remaining coal units decrease (due to the costs of environmental controls), the electricity sector shifts toward natural gas. The increase in natural-gas fired generation reflects both new gas units and higher capacity factors for existing gas units. The increase in natural gas-fired generation in each year is somewhat smaller than the decrease in coal-fired generation shown above in Figure C-2 because other energy sources also substitute for coal and total electricity consumption decreases somewhat in response to higher electricity prices (shown below in Figure C-8).

Figure C-5. Change in Natural Gas-Fired Generation Relative to Reference Case

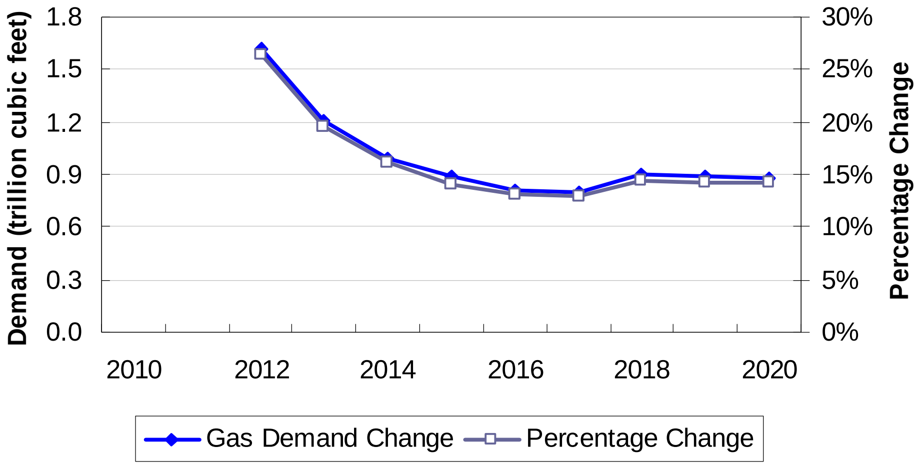


Note: Natural gas-fired generation in 2010 was 750 million MWh (EIA 2011a).
Source: NERA calculations as explained in text

5. Electricity Sector Natural Gas Demand

Figure C-6 shows the change in electricity sector natural gas demand between 2012 and 2020 due to the four EPA regulations relative to reference case projections. Just as for natural gas-fired generation, the increase in electricity sector natural gas demand reflects both new gas units and higher capacity factors for existing gas units. The percentage change in electricity sector natural gas demand in each year is similar to the percentage change in natural gas-fired generation.

Figure C-6. Change in Electricity Sector Natural Gas Demand Relative to Reference Case

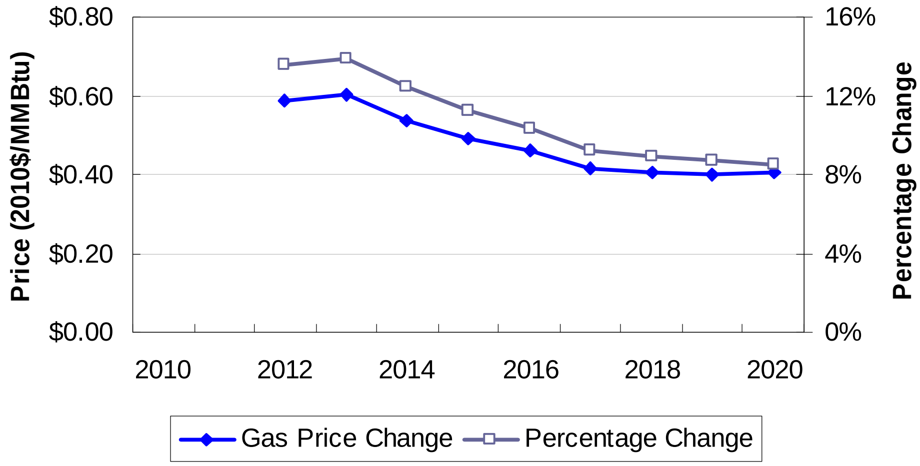


Note: Electricity sector natural gas demand in 2010 was 7.2 trillion cubic feet (EIA 2011a).
Source: NERA calculations as explained in text

6. Natural Gas Price

Figure C-7 shows the change in natural gas price at Henry Hub between 2012 and 2020 due to the four EPA regulations relative to reference case projections. The price of natural gas would increase because of the substantial increase in demand for natural gas by the electricity sector (taking into account the reduction in natural gas demand in other sectors as prices rise).

Figure C-7. Change in Natural Gas Price at Henry Hub Relative to Reference Case



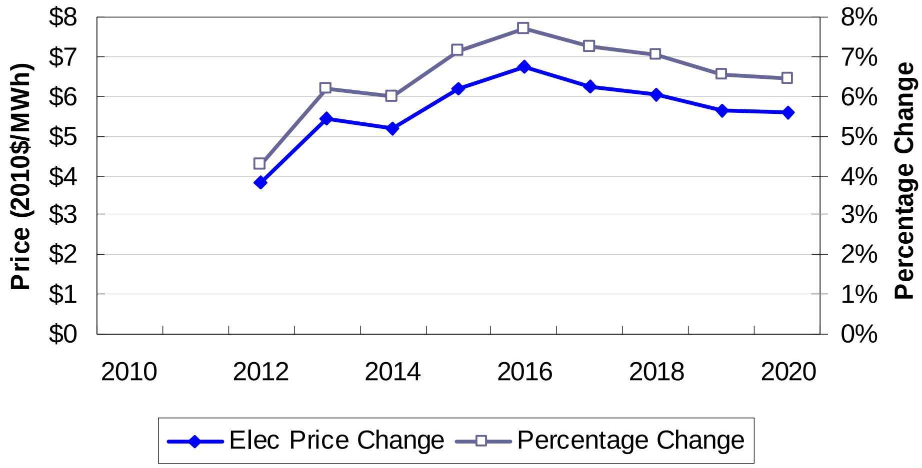
Note: Average natural gas price at Henry Hub in 2010 was $4.50/MMBtu (2010$) (EIA 2011a).
Source: NERA calculations as explained in text

7. Electricity Price

a. U.S. Electricity Price

Figure C-8 shows the change in average U.S. electricity retail price between 2012 and 2020 due to the four EPA regulations relative to reference case projections. The increase in electricity price reflects environmental control costs at coal units that do not retire, SO_2 and NO_x emission costs for CSAPR, construction of new gas units and increased capacity factors for existing gas units, and higher natural gas price.

Figure C-8. Change in Average U.S. Electricity Retail Price Relative to Reference Case

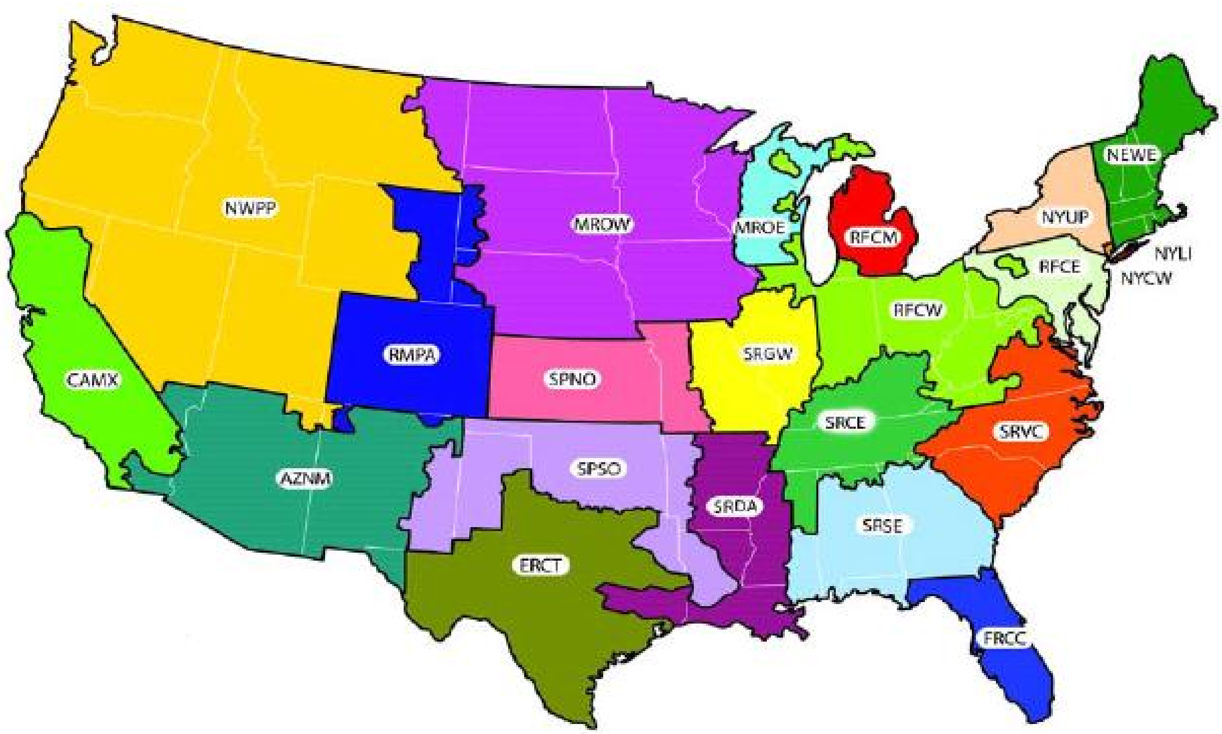


Note: Average U.S. electricity retail price in 2010 was $97/MWh (2010$) (EIA 2011a).
Source: NERA calculations as explained in text

b. Regional Electricity Price

Figure C-9 provides a map of the 22 electricity regions modeled in NEMS.

Figure C-9. NEMS Electricity Regions



Source: EIA (2011b, p. 95)

Table C-3 provides estimates of the electricity retail price impacts in the 22 NEMS electricity regions between 2012 and 2020 due to the four EPA regulations. The impacts reflect different extents to which natural gas prices, coal prices, emission allowance costs, coal unit retirements, and retrofits affect electricity prices in each year in different regions. For example, regions that rely much more on natural gas-fired generation than coal-fired generation (e.g., New England) have larger impacts during 2012-2014 than 2015-2020, because the increase in natural gas prices tapers off over time (see Figure C-7). On the other hand, regions that rely much more on coal-fired generation than natural gas-fired generation (e.g., Kentucky and Tennessee) have smaller impacts during 2012-2014 than 2015-2020, because coal unit retirements and most retrofits occur in 2015.

Table C-3. Regional Electricity Retail Price Impacts, 2012-2020 (2010$/MWh)

		2012	2013	2014	2015	2016	2017	2018	2019	2020	Avg
	US Average	+$3.80	+$5.45	+$5.21	+$6.18	+$6.73	+$6.25	+$6.06	+$5.62	+$5.56	+$5.65
NEMS Regions											
NEWE	New England	+$4.01	+$5.81	+$4.98	+$4.89	+$2.99	+$1.61	+$0.99	+$1.30	-$0.24	+$2.93
NYCW	NYC	+$6.63	+$10.35	+$8.90	+$8.12	+$6.91	+$5.95	+$5.47	+$5.21	+$5.23	+$6.97
NYLI	NY Long Island	+$10.77	+$17.39	+$15.45	+$14.09	+$12.48	+$12.22	+$11.65	+$11.40	+$11.53	+$13.00
NYUP	NY Upstate	+$6.14	+$9.37	+$8.04	+$6.65	+$5.45	+$5.33	+$5.32	+$5.59	+$5.62	+$6.39
RFCE	Mid-Atlantic	+$8.29	+$13.26	+$11.41	+$12.57	+$10.81	+$11.26	+$10.69	+$7.24	+$7.88	+$10.38
SRVC	VA & Carolinas	+$2.63	+$3.71	+$3.71	+$4.13	+$4.91	+$4.72	+$4.41	+$4.13	+$4.06	+$4.05
SRSE	Southeast	+$3.19	+$4.29	+$5.15	+$7.17	+$9.63	+$8.97	+$8.51	+$8.02	+$7.53	+$6.94
FRCC	Florida	+$3.60	+$4.81	+$4.22	+$4.22	+$4.42	+$4.20	+$3.96	+$3.64	+$3.82	+$4.10
RFCM	Lower MI	+$3.70	+$5.41	+$7.10	+$7.31	+$10.00	+$9.51	+$8.83	+$8.46	+$8.35	+$7.63
RFCW	OH, IN, & WV	+$5.42	+$8.65	+$8.08	+$7.18	+$7.12	+$6.85	+$6.59	+$6.48	+$6.70	+$7.01
SRCE	KY & TN	+$4.68	+$4.38	+$5.30	+$9.11	+$11.36	+$10.88	+$10.25	+$9.93	+$9.37	+$8.36
MROE	WI & Upper MI	+$5.63	+$7.78	+$8.12	+$6.57	+$7.37	+$7.14	+$6.79	+$6.54	+$6.66	+$6.96
MROW	Upper Midwest	+$1.41	+$1.11	+$1.23	+$4.90	+$8.36	+$8.20	+$7.94	+$7.85	+$7.54	+$5.39
SRGW	South IL & East MO	+$3.98	+$5.83	+$6.20	+$6.69	+$8.59	+$8.11	+$7.49	+$6.93	+$6.72	+$6.73
SPNO	KS & West MO	+$5.46	+$2.35	+$3.13	+$4.84	+$8.10	+$7.98	+$8.17	+$8.61	+$9.13	+$6.42
SRDA	AR, LA, & West MS	+$2.03	+$3.40	+$4.27	+$5.14	+$6.96	+$6.56	+$6.29	+$5.98	+$5.80	+$5.16
SPSO	Oklahoma	+$3.33	+$7.65	+$8.27	+$8.89	+$11.13	+$10.61	+$9.75	+$9.43	+$9.68	+$8.75
ERCT	Texas	+$4.85	+$7.01	+$6.14	+$9.15	+$6.27	+$3.51	+$4.34	+$3.60	+$3.16	+$5.34
RMPA	CO & East WY	+$0.60	+$0.40	+$0.70	+$1.54	+$2.16	+$1.99	+$1.86	+$1.72	+$1.65	+$1.40
NWPP	Northwest	-$0.14	-$0.30	-$2.27	-$1.22	-$0.07	+$0.38	+$1.20	+$1.40	+$1.36	+$0.04
AZNM	AZ & NM	+$0.82	+$0.70	+$1.04	+$1.39	+$1.71	+$1.69	+$1.56	+$1.86	+$1.85	+$1.40
CAMX	California	+$1.34	+$2.05	+$2.19	+$2.26	+$2.28	+$2.59	+$2.59	+$2.45	+$2.45	+$2.25

Source: NERA calculations as explained in text

Table C-4 shows the percentage changes in electricity retail prices in the 22 NEMS electricity regions relative to reference case projections.

Table C-4. Regional Electricity Retail Price Impacts, 2012-2020 (Percentage Changes)

		2012	2013	2014	2015	2016	2017	2018	2019	2020	Avg
	US Average	+4.3%	+6.2%	+6.0%	+7.1%	+7.7%	+7.2%	+7.0%	+6.5%	+6.5%	+6.5%
NEMS Regions											
NEWE	New England	+2.9%	+4.3%	+3.7%	+3.7%	+2.3%	+1.2%	+0.7%	+1.0%	-0.2%	+2.2%
NYCW	NYC	+3.8%	+6.1%	+5.3%	+4.9%	+4.2%	+3.6%	+3.4%	+3.2%	+3.2%	+4.2%
NYLI	NY Long Island	+6.3%	+10.4%	+9.4%	+8.7%	+7.7%	+7.6%	+7.3%	+7.1%	+7.2%	+8.0%
NYUP	NY Upstate	+5.0%	+7.9%	+6.9%	+5.8%	+4.8%	+4.7%	+4.8%	+5.0%	+5.0%	+5.6%
RFCE	Mid-Atlantic	+8.4%	+13.7%	+11.9%	+13.1%	+11.3%	+11.7%	+11.0%	+7.4%	+7.8%	+10.7%
SRVC	VA & Carolinas	+3.3%	+4.6%	+4.7%	+5.2%	+6.3%	+6.1%	+5.6%	+5.2%	+5.0%	+5.1%
SRSE	Southeast	+3.8%	+5.3%	+6.5%	+9.1%	+11.9%	+10.4%	+9.6%	+8.9%	+8.3%	+8.2%
FRCC	Florida	+3.4%	+4.5%	+4.0%	+4.0%	+4.2%	+4.0%	+3.8%	+3.5%	+3.7%	+3.9%
RFCM	Lower MI	+4.7%	+6.9%	+9.1%	+9.2%	+12.4%	+11.7%	+10.9%	+10.5%	+10.4%	+9.5%
RFCW	OH, IN, & WV	+6.2%	+10.2%	+9.7%	+8.7%	+8.7%	+8.5%	+8.3%	+8.3%	+8.6%	+8.6%
SRCE	KY & TN	+7.2%	+6.9%	+8.5%	+14.7%	+18.6%	+17.9%	+17.0%	+16.5%	+15.5%	+13.6%
MROE	WI & Upper MI	+7.6%	+10.5%	+10.7%	+8.7%	+9.4%	+9.3%	+8.9%	+8.7%	+8.8%	+9.2%
MROW	Upper Midwest	+2.0%	+1.6%	+1.7%	+7.0%	+12.1%	+11.9%	+11.6%	+11.6%	+11.3%	+7.9%
SRGW	South IL & East MO	+6.5%	+9.6%	+10.3%	+11.0%	+14.1%	+13.3%	+12.4%	+11.5%	+11.2%	+11.1%
SPNO	KS & West MO	+6.9%	+2.8%	+3.7%	+5.8%	+9.9%	+9.9%	+10.4%	+11.1%	+12.0%	+8.1%
SRDA	AR, LA, & West MS	+2.7%	+4.6%	+5.9%	+7.1%	+9.9%	+9.4%	+9.0%	+8.7%	+8.4%	+7.3%
SPSO	Oklahoma	+4.7%	+11.1%	+12.0%	+12.8%	+16.0%	+15.3%	+14.1%	+13.6%	+14.0%	+12.6%
ERCT	Texas	+6.4%	+9.4%	+8.3%	+12.2%	+8.1%	+4.4%	+5.5%	+4.5%	+3.9%	+7.0%
RMPA	CO & East WY	+0.7%	+0.4%	+0.8%	+1.7%	+2.4%	+2.2%	+2.1%	+1.9%	+1.9%	+1.6%
NWPP	Northwest	-0.2%	-0.5%	-3.7%	-2.0%	-0.1%	+0.6%	+2.1%	+2.5%	+2.5%	+0.1%
AZNM	AZ & NM	+1.0%	+0.8%	+1.2%	+1.6%	+1.9%	+1.9%	+1.8%	+2.1%	+2.1%	+1.6%
CAMX	California	+0.9%	+1.4%	+1.5%	+1.6%	+1.6%	+1.9%	+1.9%	+1.8%	+1.8%	+1.6%

Source: NERA calculations as explained in text

D. References

Brattle Group. 2010. *Potential Coal Plant Retirements Under Emerging Environmental Regulation*. Cambridge, MA: Brattle Group, December 8.

U.S. Energy Information Administration. 2009. *The National Energy Modeling System: An Overview 2009*. Washington, D.C.: EIA, October. (www.eia.gov/FTPROOT/-forecasting/05812009.pdf, accessed September 20, 2011)

U.S. Energy Information Administration. 2011a. *Annual Energy Outlook 2011*. Washington, D.C.: EIA, April. (www.eia.gov/forecasts/aeo/pdf/0383(2011).pdf, accessed September 20, 2011)

U.S. Energy Information Administration. 2011b. *Assumptions to the Annual Energy Outlook 2011*. Washington, D.C.: EIA, July. (www.eia.gov/forecasts/aeo/assumptions/pdf/-0554(2011).pdf, accessed September 20, 2011)

Appendix D: Macroeconomic Modeling

This appendix provides details on the Policy Insight Plus (PI+) macroeconomic model developed and licensed by Regional Economic Models, Inc. (REMI) as well as our data and methodology for using this model to estimate the potential macroeconomic impacts of the EPA regulations.

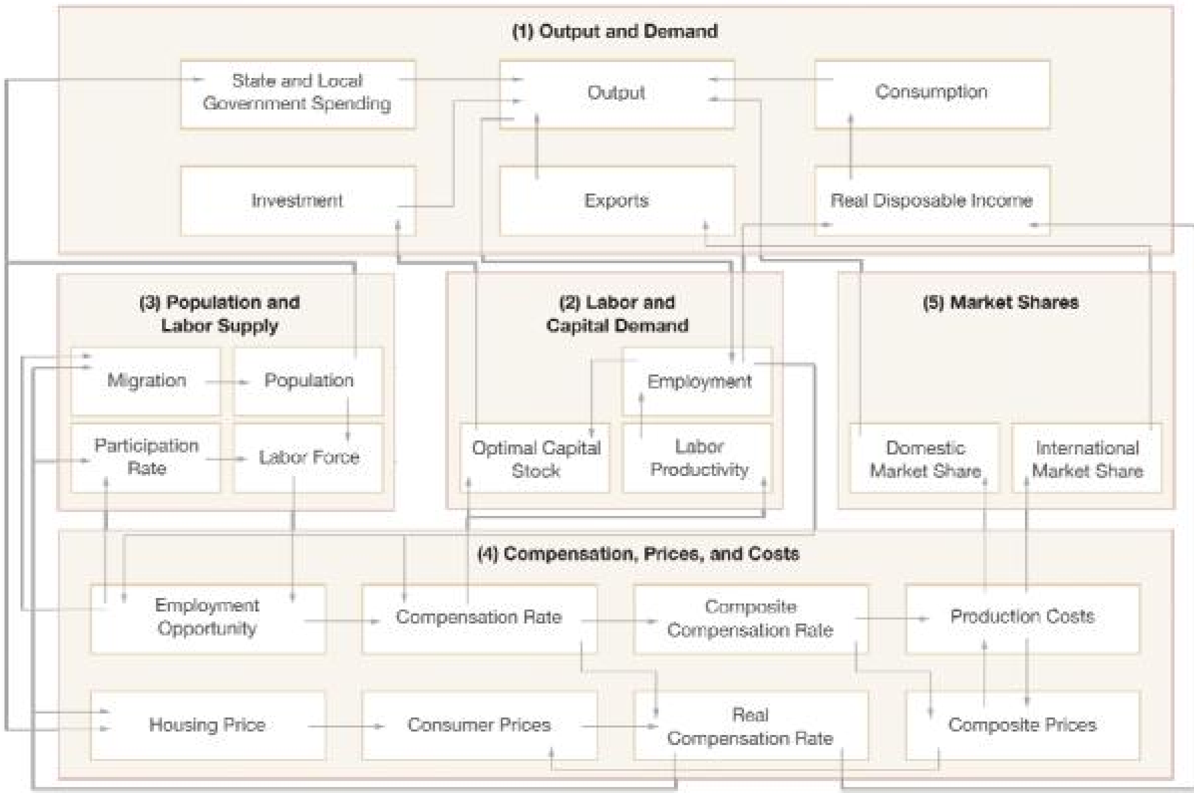
A. Overview of REMI Model[1]

The REMI PI+ model produces estimates of the changes in employment, gross domestic product (GDP), disposable personal income (i.e., personal income after taxes), and other macroeconomic variables due to changes in supply, demand, prices, and other types of inputs. Each version of the REMI PI+ model is custom-built for the regions of interest, which can range from counties to entire countries. The REMI PI+ model incorporates detailed and up-to-date macroeconomic data from the U.S. Bureau of Economic Analysis, the U.S. Bureau of Labor Statistics, the U.S. Census Bureau, and other public sources. The REMI PI+ model is widely used by federal, state, and local agencies, as well as analysts in the private sector and academia, to estimate the effects of regulations, investments, closures, and other scenarios.

Figure D-1 shows the five blocks in the REMI PI+ model and their linkages. The Output and Demand block balances supply and demand for all major sectors of the economy, including both domestic and international sources of supply and demand. The Labor and Capital Demand block models employment and capital stock based on output, wage rates, and capital costs. The Population and Labor Supply block models labor participation rate and population based on wage rates in the various regions and the size of the various sectors. The Compensation, Prices, and Costs block models each sector's production cost, including labor cost based on wage rates. Finally, the Market Shares block uses production cost to model each sector's domestic market share and international market share, which are passed back up to the Output and Demand block.

1 This section draws on model documentation from Regional Economic Models, Inc. (REMI 2011).

Figure D-1. Key Blocks and Linkages in the REMI Model



Source: REMI (2011)

B. Overview of Methodology

We modeled the potential macroeconomic impacts of the EPA regulations using a 70-sector REMI PI+ model covering the entire United States. The model has regional detail based on Census divisions.

We developed inputs to the REMI model using the energy market modeling results from NEMS for the four EPA regulations.[2] Inputs to the REMI model can take the form of either dollar amounts or percentage changes from the built-in forecasts in the model. We entered all our inputs for this study as dollar amounts measured in constant dollars.

The types of REMI inputs developed from NEMS and other sources are summarized below.

1. *Environmental control costs.* We developed inputs for the positive effects of the capital and operations and maintenance (O&M) costs of environmental controls at the coal units that do not retire. These inputs include the costs of all the projected scrubbers, SCR, ACI, fabric filters, DSI, and compliance measures for the CCR and 316(b) regulations, broken out to the specific model regions in which they are projected to occur. We used the same cost

[2] Details on the energy market modeling results from NEMS are provided in Appendix C.

assumptions as those used in modeling potential coal unit retirements. These capital and O&M costs enter the REMI model as increased demand for machinery manufacturing and construction.

2. *Replacement capacity costs*. We developed REMI inputs for the positive effects of capital costs of new generation capacity to replace the coal units that are projected to retire. Most of the replacement capacity is combined-cycle gas technology. We developed estimates of the capital costs of replacement capacity using energy market modeling results and capital cost assumptions from NEMS. These capital costs enter the REMI model as increased demand for machinery manufacturing and construction.[3] The costs are apportioned to model regions based upon the regions where NEMS has projected the construction of new units will occur.

3. *Coal sales decreases*. We developed REMI inputs reflecting the negative effects of reductions in coal sales. These reductions arise both from coal unit retirements and from the lower capacity factors for coal units that continue to operate but are utilized less because their generation costs are greater due to controls. We developed estimates of reductions in coal sales using regional coal production and mine mouth (i.e., wholesale) price results from NEMS. The NEMS results reflect estimates of changes in coal demand not only in the electricity sector but also in the residential, commercial, and industrial sectors; the changes in these other sectors are small because these other sectors consume very little coal relative to the electricity sector. The values enter the REMI model as decreased sales for the mining sector in the relevant regions.

4. *Coal price decreases*. We developed REMI inputs for the negative impacts of decreases in coal prices on producers due to the decreased demand for coal in the electricity sector. The gains to electricity consumers from the lower coal prices are included below in the estimated effects of changes in electricity prices (which reflect the net effect of compliance costs and changes in fuel costs). In principle, the reductions in coal prices would lead to gains to consumers in non-electric sectors. NEMS does not provide information on coal prices and costs for these sectors that would allow us to assess these potential effects but they would be small because non-electric coal use is a small fraction of utility coal use.[4] We developed estimates of the decreases in coal prices using regional coal production and mine mouth (i.e., wholesale) price results from NEMS. The negative impacts on producers enter the REMI model as decreases in dividend income and government transfer payments (due to the decrease in government tax receipts from lower dividend income taxes).

---

[3] The O&M costs of replacement capacity are assumed to be approximately equal to the avoided O&M costs of the coal units that retire. Thus, neither the O&M costs of replacement capacity nor the avoided O&M costs of the coal units that retire are entered into the REMI model, as they would cancel each other out. Since O&M costs of the generating units themselves are small relative to the other inputs to the REMI model, omission of the O&M costs of replacement capacity and coal units that retire does not significantly affect the results of the macroeconomic modeling. In contrast, we do include inputs to reflect the O&M costs of new retrofits as noted above.

[4] The residential, commercial, and industrial sectors collectively accounted for less than 7 percent of total U.S. coal consumption in 2010 (EIA 2011a). Coal price effects for these sectors are considerably smaller than any other effect included in this macroeconomic impact analysis.

5. *Natural gas sales increases*. We developed REMI inputs for the positive impacts of increases in natural gas sales due to the increase in demand from the electricity sector (from new natural gas units replacing the coal units that retire and higher capacity factors for existing gas units). The net increase in natural gas sales, however, is smaller than the increase in electricity demand because the increases in natural gas prices lead to reduced demand from residential, commercial and industrial sectors.[5] We developed estimates of the net increase in natural gas sales using regional natural gas production and wellhead (i.e., wholesale) price results from NEMS. The values enter the REMI model as increased sales for the oil and gas extraction sector.

6. *Natural gas price increases*. We developed REMI inputs for both the positive impacts on natural gas producers of higher natural gas prices (relative to cost increases) and the negative effects of higher natural gas prices on non-utility consumers. (As with coal prices, the negative effects on electric company customers are included in the electricity price impacts.) We developed regional estimates of the increase in natural gas prices using regional natural gas consumption and retail price results for the residential, commercial, and industrial sectors from NEMS. The impacts on consumers enter the REMI model for households as decreases in purchasing power due to increases in natural gas prices and for commercial and industrial sectors as increases in natural gas costs. The impacts on producers enter the REMI model as increases in dividend income and government transfer payments (due to the increase in government tax receipts associated with dividend income taxes).

7. *Electricity price increases*. We developed REMI inputs for the negative impacts of increases in electricity prices on consumers (residential, commercial, and industrial). Because changes in electricity sector costs—for pollution control equipment and fuel price changes—are reflected in electricity prices, electricity producers as a group are not expected to be affected. We developed regional estimates of the increase in electricity prices for consumer groups using regional electricity consumption and retail price results for the residential, commercial, and industrial sectors from NEMS. These values enter the REMI model as increases in electricity price (change in purchasing power) for households and electricity costs for commercial and industrial sectors in the various regions.

8. *Financing of capital costs*. This component arises because the capital costs for pollution control and new capacity are not reflected fully in electricity rates in the years in which they are incurred, although these costs are ultimately reflected in higher electricity rates (as noted above). We developed information on the financing of pollution control and replacement capacity expenditures, in particular the extent to which these capital expenditures would lead to reduced investment or reduced consumption in the years in which the capital expenditures are made, and then increased investment or increased consumption in the years in which

[5] We used the version of REMI that allows for complete fuel substitution for other factor inputs, which assumes that consumers can shift away from more expensive energy and thus reduce the negative impacts of higher natural gas and electricity prices. This assumption may understate the negative imacts of the price increases. We also entered the costs of substitution away from energy into the REMI model as increased demand for energy-efficient appliances. Including this effect may overstate the positive impacts if the REMI model already incorporates these positive adjustments related to substitution away from energy.

electricity price increases reflect these capital costs but the capital expenditures have already been made.

C. Information on Modeling Components

This section provides additional information on the inputs to the REMI modeling.[6]

1. Environmental Control Costs

Environmental control costs consist of the capital and O&M costs for compliance measures at the coal units that do not retire. As discussed in the report body, we assumed that CSAPR would take effect in 2012 and MACT, CCR, and 316(b) would take effect in 2015. The NEMS results reflect compliance in these years, but that model does not incorporate leadtimes for controls. NEMS builds some scrubbers for compliance with the CSAPR SO_2 policy in 2012, and it builds other controls by 2015. We entered the capital costs of controls installed in 2012 into the REMI model as costs in 2012, and we entered the capital costs of controls installed in 2015 into the REMI model as costs spread evenly in 2013, 2014, and 2015 to reflect their leadtime. Costs from 2016 onward primarily reflect the O&M cost of environmental controls. The costs are net of pollution control costs in the reference scenario (which primarily reflect currently planned retrofits by 2012 and mercury controls for state policies in the reference case).

The environmental control costs represent increased demand for manufacturers and construction companies. We reviewed detailed budgets for several retrofit projects in the electricity sector (e.g., PSNH 2010, DOE 2003) and determined that approximately 70 percent of the costs were for equipment and 30 percent for construction. Thus, we modeled 70 percent of the environmental control costs in each year in REMI as increased demand for the machinery manufacturing sector and the remaining 30 percent as increased demand for the construction sector. These environmental control costs are allocated to regions in REMI based on the locations of the coal units incurring the costs.

2. Replacement Electricity Capacity Costs

Replacement capacity costs consist of the capital costs for new electricity capacity (primarily combined-cycle gas units) that NEMS projects will be built, based on its evaluation of supply and demand in regional electricity markets, to replace the coal units that retire.[7] Most of the

---

[6] We considered using the optional NEMS macroeconomic activity module to develop the macroeconomic impact estimates but concluded that it would be less appropriate than REMI for this study. The NEMS macroeconomic module uses only changes in energy prices and quantities from NEMS to assess macroeconomic impacts. Thus, the module does not account for the increase in demand for machinery manufacturing and construction or the need to finance the capital expenditures. REMI allows us to incorporate both effects. Moreover, the NEMS macroeconomic module aggregates all energy price changes (including electricity, coal, and natural gas) into a single energy price index for purposes of evaluating macroeconomic impacts. REMI allows us to input separate estimates for the different energy types.

[7] As noted above, neither the O&M costs for replacement capacity nor the avoided O&M costs for coal units that retire are included in the macroeconomic modeling, because they are assumed to be approximately equal in size and therefore would cancel each other out.

replacement capacity is built shortly before 2015 in anticipation of the many coal unit retirements in that year, but some replacement capacity is built later in the modeling period. The assumed capital costs for new capacity are based upon EIA estimates (2011b, p. 97). The replacement capacity costs are net of new capacity costs in the reference scenario. (The four policies pull forward some new capacity that would be built later in the reference scenario.)

The replacement capacity costs represent increased demand for manufacturers and construction companies. Based on our review of electricity sector project budgets (described above), we assumed that 70 percent of the capital costs were for equipment and 30 percent for construction. Thus, we modeled 70 percent of the replacement capacity costs in each year in REMI as increased demand for the machinery manufacturing sector and the remaining 30 percent as increased demand for the construction sector.

NEMS generates estimates of replacement capacity costs for each of its 22 electricity regions, which are based on electric reliability regions defined by the North American Electric Reliability Corporation (NERC). We allocated these values to the regions in the REMI model based upon the shares of baseline generation capacity.

3. Coal Sales Reduction

The coal unit retirements and reduction in capacity factors for non-retiring coal units projected due to the four regulations would lead to decreased demand for coal in the electricity sector. We modeled the reduction in coal sales using regional NEMS results on coal production and minemouth (i.e., wholesale) price. In particular, we calculated the change in coal production in each region and multiplied it by the average of the minemouth prices in the reference case and policy case in each region to capture the quantity effect of the four regulations for coal.[8] We allocated these values to the regions in the REMI model based on the regional data from NEMS. The values enter the REMI model as decreased sales for the mining sector.

4. Coal Price Decreases

This section considers the effects of coal price decreases on producer surplus. As noted above, we did not model coal price effects on consumers because the price effect for the electricity sector is included in the electricity price effects and the price effects for residential, commercial, and industrial sectors are negligible because of their low coal consumption.

The reduction in coal prices due to reduced demand by the electricity sector would reduce producer surplus in the coal sector.[9] We developed REMI inputs for this reduction in producer surplus in the coal sector based on NEMS results by multiplying the change in coal minemouth price (a negative value) by the average of coal productions in the reference and policy cases. We entered the reduction in producer surplus into the REMI model as reductions in dividend income and allocated it across regions based on their share of the U.S. population. Since dividends are

---

8 The price effects on consumer and producers surplus are modeled below.

9 Producer surplus is the amount by which price exceeds marginal cost (or the minimum amount that producers would accept to produce the good), summed over all production. It relates to total profit in a sector.

distributed by companies after paying income taxes, we first multiplied the producer surplus by an estimated effective corporate income tax rate and modeled this change in government corporate income tax receipts as a change in transfer payments. We used an estimated effective corporate income tax rate of 40 percent based on a review of tax rates for energy companies (API 2010, p. 7) and allocated the change in transfer payments across regions based on their share of the U.S. population. We then modeled the remainder of producer surplus as dividend payments.

5. Natural Gas Sales Increase

The new gas units and higher capacity factors for existing gas units due to the four regulations would lead to increased demand for natural gas in the electricity sector. Since higher natural gas prices in the REMI model lead to lower natural gas sales, but the regulations would lead to both higher natural gas prices and higher natural gas sales due to the outward shift of the demand curve for natural gas in the electricity sector, we needed to calibrate the natural gas sales inputs to ensure that the REMI results would be consistent with the NEMS results for natural gas sales. We did this by running the REMI model first with the inputs shown above except the change in natural gas sales, examining the natural gas sales results from the REMI model, and calibrating the natural gas sales inputs to correspond with the values from NEMS. We modeled the increase in natural gas sales using regional NEMS results on natural gas production and wellhead (i.e., wholesale) price. In particular, we calculated the change in natural gas production in each region and multiplied it by the average of the wellhead prices in the reference case and policy case in each region to capture the quantity effect of the four regulations for natural gas. We allocated these values to the regions in the REMI model based on the regional data from NEMS. The values enter the REMI model as increased sales for the oil and gas extraction sector.

6. Natural Gas Price Increases

This section considers the impacts of increases in natural gas prices—due to increased electricity sector demand—on consumers and producers.

a. Impacts on Natural Gas Consumers

The increase in natural gas demand in the electricity sector would increase the price of natural gas for all sectors of the economy. We used regional NEMS results on natural gas consumption and retail prices for the residential, commercial, and industrial sectors to develop REMI inputs for these adverse consumer impacts. NEMS produces these results for the nine Census divisions. We calculated the change in retail natural gas price in each region and multiplied it by the average consumption in the reference and policy cases in each region to capture the price effect of the four regulations for natural gas. We allocated these values to the regions in the REMI model based on their historical shares of natural gas expenditures in their Census divisions. We entered the values for the residential sector in the REMI model as decreased household purchasing power (reflecting the increased natural gas prices), and we entered the values for the commercial and industrial sectors as increased natural gas costs for these sectors.

b. Impacts on Natural Gas Producers

The increase in natural gas prices due to expanded demand by the electricity sector would increase producer surplus in the natural gas sector. As with producer surplus in the coal sector, we modeled the increase in natural gas as increases in dividend payments and government transfer payments, using an effective corporate income tax rate of 40 percent. The change in producer surplus is calculated as the change in wellhead price multiplied by the average production in the reference and policy cases.

7. Electricity Price Increases

The four regulations would lead to increases electricity prices for the residential, commercial, and industrial sectors. We used regional NEMS results on electricity consumption and retail prices for the residential, commercial, and industrial sectors to develop REMI inputs for this type of impact.[10] NEMS produces these results for the nine Census divisions. We calculated the change in retail electricity price in each region and multiplied it by baseline consumption in each region to capture the price effect of the four regulations for electricity. We allocated these values to the regions in the REMI model based on their historical shares of electricity expenditures in their Census divisions. We entered the values for the residential sector in the REMI model as increased electricity price (change in purchasing power) for households, and we entered the values for the commercial and industrial sectors as increased electricity costs for these sectors.

8. Financing of Capital Costs

We presume that electricity companies would finance the net capital cost requirements (capital costs for environmental controls and new capacity minus contemporaneous electricity rate increase due to financing) in each year through debt financing. The impacts on the economy in each year would depend in part upon the extent to which the increased utility demand for capital—primarily from 2012 to 2015, with much smaller investment required from 2016 onward for replacement capacity–would lead to reductions in investment elsewhere in the economy, i.e., crowd out other investment. Since the REMI model does not reflect changes in the overall productivity of the economy due to changes in investment, however, the distinction between changes in investment and changes in consumption as the source of financing is less important.[11]

The extent of crowding out of other investment depends upon the short-run demand and supply elasticities for investment capital as well as on the detailed general equilibrium effects in the overall economy. If the short-run capital supply elasticity is zero, as many researchers have found (see Bernheim 2002), 100 percent of the increased demand by the electricity companies would be reflected in reduced investment elsewhere.

[10] Note that the changes in retail electricity prices from NEMS reflect the annualized costs of environmental controls and replacement capacity, not the actual expenditures by the electricity sector in each year. This issue is discussed below in the context of financing.

[11] Studies suggest that the general equilibrium economic effects of crowding out productive investment could be substantial. See Schmalensee (1994).

Various studies have considered the specific crowding out of pollution control expenditures. Gray and Shadbegian (2001) find that pollution control expenditures in the pulp and paper sector actually lead to more than a 100 percent reduction in other capital expenditures in the sector when account is taken of reductions at individual plants (188 percent decline) and approximately 100 percent decline considering only capital expenditures at other facilities. Jorgenson and Wilcoxen (1990) in their study of the effects of pollution control expenditures on the U.S. economy use a short-run elasticity for the supply of capital of zero (i.e., perfectly inelastic), implying 100 percent crowding out of investment in the short-term.

One plausible alternative is to assume 100 percent crowding out of private investment, based upon estimates of a zero short-term elasticity of supply of capital and some of the empirical estimates for compliance costs. Since the elasticity of supply may be greater than zero, we assumed crowding out of 50 percent for the net investment years.[12] We presumed that that the other 50 percent of net utility investment would come from additional savings and thus reduced consumption.[13] We presumed that the bondholders would receive additional income in the later years.

The reduced private investment is entered into REMI as reduced investment in residential structures, nonresidential structures, and nonresidential equipment based on their shares of baseline U.S. investment. The change in income for bondholders is entered into the REMI model as changes in consumption.[14]

D. Modeling Results for the Four Environmental Policies

We modeled the potential net macroeconomic impacts of the four regulations by entering all the inputs categories described above into the REMI model. We also calibrated the REMI model to ensure that the net changes in sales for the coal, natural gas, and electricity sectors with all the inputs were consistent with their net changes in sales from NEMS.[15]

---

[12] If the modeling included the negative effects of crowding out productive investment on economic growth, it would be more important to be precise about the specific amount of crowding out of private investment.

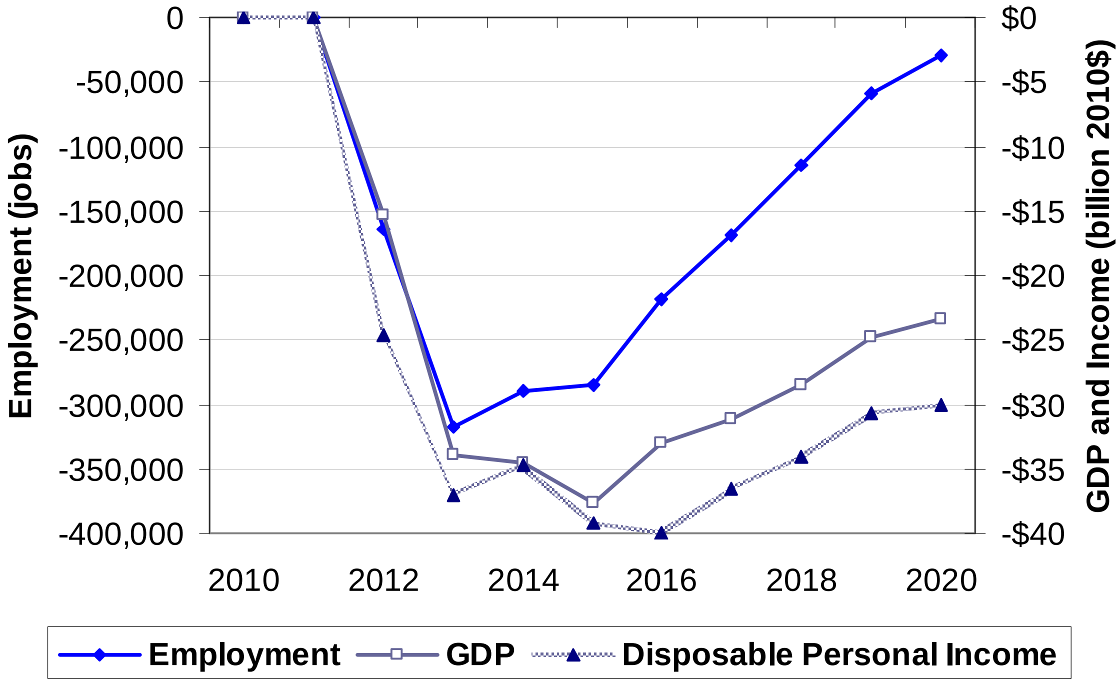
[13] These calculations presume that environmental compliance expenditures do not use unemployed or idle resources. As Schmalensee (1994) points out, there is no reason why tightening environmental regulation would weaken economy-wide forces that produce unemployment and, indeed, that the net short-term impact of tightening environmental standards is likely to increase overall unemployment in the near term in the process of shifting jobs within the economy (with monetary and fiscal policies, changes in exchange rates, changes in foreign economic policies and economic conditions and firm and household expectations being the major factors determining overall macroeconomic conditions).

[14] Entering the change in income alternatively as a change in dividends, interest, and rent would yield very similar results (because REMI indicates that dividends, interest, and rent in any year are mostly used for consumption in that same year).

[15] We performed this calibration by (1) running REMI once with all inputs except changes in sales; (2) calculating the difference between changes in sales from REMI for the coal, natural gas, and electricity sectors and their changes in sales from NEMS; and (3) running REMI again with the difference in sales (in addition to other inputs) so that the sales results from REMI would be consistent with the sales results from NEMS.

Figure D-2 shows the annual impacts of the four environmental policies on U.S. employment, GDP, and disposable personal income from 2012 to 2020 predicted by the REMI model.

Figure D-2. Macroeconomic Modeling Results



Source: NERA calculations as explained in text

E. References

American Petroleum Institute. 2011. *Putting Earnings in Perspective: Facts for Addressing Energy Policy*. Washington, D.C.: API, July 12. (www.api.org/statistics/-earnings/upload/earnings_perspective.pdf, accessed September 20, 2011)

Bernheim, B. Douglas. 2002. "Taxation and Saving", ch. 18, p. 1173-1249 in Auerbach, A. J. and Feldstein, M. eds., *Handbook of Public Economics*, vol. 3, Elsevier.

Gray, W. B. and Shadbegian, R. J. 1998. "Environmental Regulation, Investment Timing, and Technology Choice." *The Journal of Industrial Economics* 46: 235–256.

Jorgenson, Dale W. and Peter J. Wilcoxen. 1990. "Environmental Regulation and U.S. Economic Growth." *RAND Journal of Economics* 21(2): 314-340.

Public Service of New Hampshire. 2010. *Clean Air Project: Merrimack Station*. Prepared for the New Hampshire Public Utilities Commission: Docket 08-103 Informational Session. March 31. (www.puc.nh.gov/Regulatory/CaseFile/2008/08-103/LETTERS,%20MEMOS/08-103%202010-03-31%20PSNH%20Clean%20Air%20Project.pdf, accessed September 20, 2011)

Regional Economic Models, Inc. 2011. "The REMI Model." (www.remi.com/index.php?page=model&hl=en_US, accessed September 20, 2011)

Schmalensee, Richard. 1994. *The Costs of Environmental Protection,* in *Balancing Economic Growth and Environmental Goals*, Washington, D.C.: American Council for Capital Formation Center for Policy Research, pp. 55-80.

U.S. Department of Energy. 2003. *An Investigation of Site-Specific Factors for Retrofitting Recirculating Cooling Towers at Existing Power Plants*. Prepared for the U.S. DOE National Energy Technology Laboratory by Parsons Infrastructure and Technology Group, Inc. January 22. (www.netl.doe.gov/technologies/coalpower/ewr/water/pdfs/316b_NETL_ParsonFinalReport_wAddnd_012203.pdf, accessed September 20, 2011)

U.S. Energy Information Administration. 2011a. *Annual Energy Outlook 2011*. Washington, D.C.: EIA, April. (www.eia.gov/forecasts/aeo/pdf/0383(2011).pdf, accessed September 20, 2011)

U.S. Energy Information Administration. 2011b. *Assumptions to the Annual Energy Outlook 2011*. Washington, D.C.: EIA, July. (www.eia.gov/forecasts/aeo/assumptions/pdf/-0554(2011).pdf, accessed September 20, 2011)

NERA Economic Consulting
200 Clarendon Street, 11th Floor
Boston, Massachusetts 02116
Tel: +1 617 927 4500
Fax: +1 617 927 4501
www.nera.com