



EPA's Regulation of Coal-Fired Power: Is a "Train Wreck" Coming?

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Summary

Given the central role of electric power in the nation's economy, and the importance of coal in power production, concerns have been raised recently about the cost and potential impact of regulations under development at the Environmental Protection Agency (EPA) that would impose new requirements on coal-fired power plants. Six of the rules, which have drawn much of the recent attention, are Clean Air Act regulations. Two others are Clean Water Act rules, and one is a Resource Conservation and Recovery Act rule. The majority are expected to be promulgated over the next 18 months. All together, these rules have been characterized by critics as a regulatory "train wreck" that would impose excessive costs and lead to plant retirements that could threaten the adequacy of electricity capacity (i.e., reliability of supply) across the country, especially from now through 2017.

Although some question why EPA is undertaking so many regulatory actions in such a short time-frame, supporters of the regulations assert that it is decades of regulatory delays and court decisions that have led to this point, resulting in part from special consideration given electric utilities by Congress under several statutes. Further, several of the current regulatory developments have been under consideration for a decade or longer, or are being reevaluated after an earlier action was vacated or remanded to EPA by the courts. The regulations are supported by proponents and EPA as having substantial benefits for public health and the environment.

Recent reports by industry trade associations and others have discussed potential harm of EPA's prospective regulations to U.S. electricity generating capacity, with emphasis on coal-fired generation. One of these reports, by the Edison Electric Institute, which represents investor-owned utilities, has attracted considerable attention by depicting a timeline in which multiple rules would take effect more or less simultaneously over the next five years. Congress has shown significant interest in these issues, and bills have been introduced that would de-fund or restrict EPA's ability to develop rules, and which would legislate new regulatory analytic requirements. This report describes nine rules in seven categories that are at the core of recent critical analyses, with background on the rule and its requirements and, where possible, a discussion of the rule's potential costs and benefits.

The EEI and other analyses discussed here generally predate EPA's actual proposals and reflect assumptions about stringency and timing (especially for implementation) that differ significantly from what EPA actually may propose or has promulgated. Some of the rules are expected to be expensive; costs of others are likely to be moderate or limited, or they are unknown at this point because a rule has not yet been proposed. Rules when actually proposed or issued may well differ enough that a plant operator's decision about investing in pollution controls or facility retirement will look entirely different from what these analyses project. Further, promulgation of standards is not the end of the road: court challenges are likely, potentially delaying implementation for years, and even when final, EPA rules must be adopted by states and implemented over time through state-issued permits.

The primary impacts of many of the rules will largely be on coal-fired plants more than 40 years old that have not, until now, installed state-of-the-art pollution controls. Many of these plants are inefficient and are being replaced by more efficient combined cycle natural gas plants, a development likely to be encouraged if the price of competing fuel—natural gas—continues to be low, almost regardless of EPA rules.

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Introduction

Given the central role of electric power in the nation's economy, and the importance of coal in power production, concerns have been raised about the cost and potential impact of numerous regulatory actions that would impose new requirements on coal-fired power plants. In the summer of 2010, for example, the Edison Electric Institute (EEI), which represents the nation's investor-owned electric utilities, prepared a chart, "Possible Timeline for Environmental Regulatory Requirements for the Electric Utility Industry," which is reproduced here as **Figure 1**. Using color-coded categories, the chart identified rules under development at the U.S. Environmental Protection Agency (EPA) and depicted a schedule for development and implementation of the rules between 2008 and 2017.

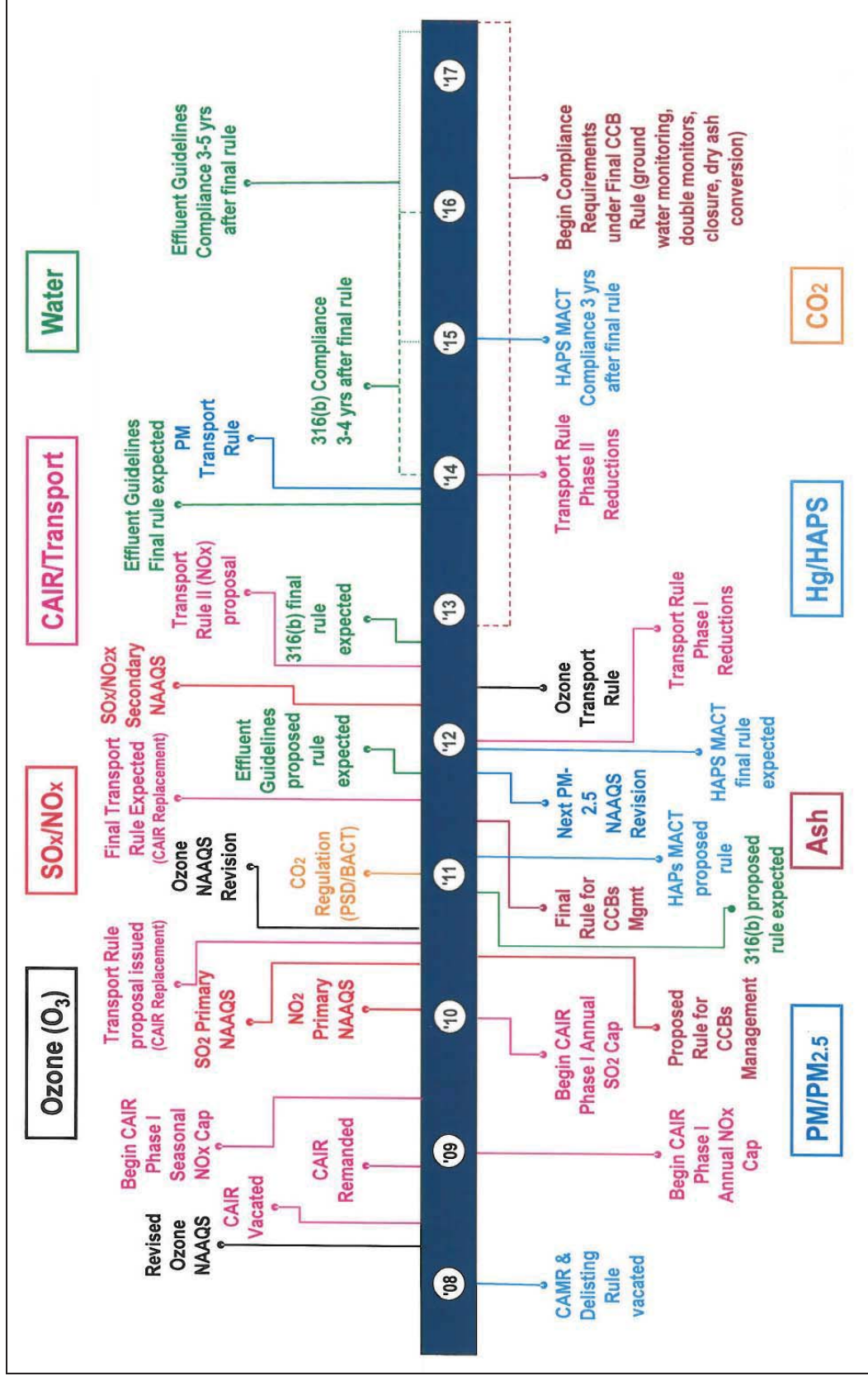
The rules identified by EEI were:

- the Cross-State Air Pollution Rule, and its predecessor, the Clean Air Interstate Rule (identified as "CAIR/Transport" on the timeline), which would establish cap-and-trade programs for utility emissions of sulfur dioxide and nitrogen oxides;
- Maximum Achievable Control Technology emission standards for mercury and other hazardous air pollutants, a rule generally referred to as the "Utility MACT" ("Hg/HAPS" on the timeline);
- National Ambient Air Quality Standards (NAAQS) for ozone, sulfur dioxide, nitrogen dioxide, and particulate matter ("Ozone," "SO_x/NO_x," and "PM/PM_{2.5}" on the timeline);
- regulation of greenhouse gas emissions ("CO₂" on the timeline);
- cooling water intake regulations ("316(b)" on the timeline);
- clean water effluent guidelines (identified under "Water" on the timeline); and
- coal combustion waste management rules ("Ash" or "CCBs Management").

EEI subsequently produced a report, *Potential Impacts of Environmental Regulation on the U.S. Generation Fleet*, which concluded that new EPA regulations would cause the unplanned retirement of 17 to 59 gigawatts (GW) of coal-fired electric capacity (5.4% to 18.8% of the current coal-fired total of about 315 GW) by 2015, and would require incremental capital expenditures of \$85 billion to \$129 billion.¹

¹ ICF International, *Potential Impacts of Environmental Regulation on the U.S. Generation Fleet*, Final Report, prepared for the Edison Electric Institute, January 2011, available at http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2011IRP/EEIModelingReportFinal-28January2011.pdf. Hereinafter referred to as the "EEI report."

Figure 1. EEl's Timeline for Environment Requirements for the Electric Utility Industry



Source: Edison Electric Institute, <http://www.eei.org/whatwedo/PublicPolicyAdvocacy/TFB%20Documents/100525SheaCongressCoalImpacts.pdf> (Figure 7).

EEI is not the only group to have focused on EPA's prospective regulations. The American Legislative Exchange Council (ALEC) picked up EEI's chart, added to it the separate EPA rules that will affect industrial and commercial boilers, and labeled it "EPA's Regulatory Train Wreck." The National Mining Association also refers to "EPA's Regulatory Train Wreck" in materials that it distributes, and the North American Electric Reliability Corporation (NERC), in an October 2010 Special Reliability Assessment, concluded that implementation of four EPA rules could result in a loss of up to 19% of fossil-fuel-fired steam capacity in the United States by 2018, with the potential for "significantly deteriorating future ... system reliability."² In addition to these, a large number of other analyses have been prepared by other policy and research groups; some are similarly critical of EPA's rules, while others counter or rebut the criticisms. Many of these reports are identified below in **Appendix B**.

The "train wreck" charts and related studies have been widely circulated on Capitol Hill, where they have stimulated concern. Several bills aimed at reducing the regulatory burden or requiring additional analyses of the combined rules' impacts have been introduced, as have proposals to modify or delay implementation of specific EPA rules. As discussed below in "Legislation," as of August 2011, three of these bills had passed the House.

Opponents of these bills maintain that regulation of the affected plants is overdue. Coal-fired power plants are major sources of pollution; many are decades old; and regulation of their emissions, effluent, and waste has lagged that of other industries.

Coal's Place in Electric Power Production

Coal fueled 44.6% of the nation's electric power in 2009. This was a decline from 52% in 2000, but coal is still the electric power industry's dominant fuel source (as shown in **Figure 2**).

Many coal-fired electric generating units, along with most nuclear and hydroelectric plants, provide what is called "base-load" power. Many of the plants run 24 hours a day and provide the relatively cheap power that is the foundation of electric service. (Other plants, known as peaking plants, are brought into service at times of peak demand. Peaking plants tend to have higher operating costs, but since they operate for short periods of time, the higher cost is of less concern.)

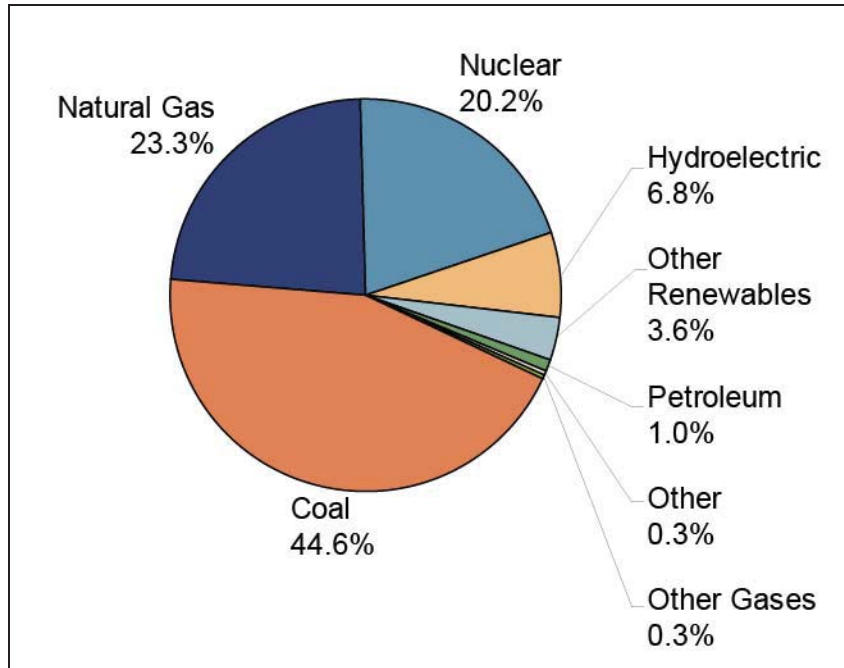
Low Cost

Coal-fired power has been cheap for multiple reasons. The average coal-fired power plant is more than 40 years old and its capital cost fully amortized, whereas many natural gas plants (the second largest source, producing about 23% of the nation's electricity) have been built in the last 10 years. Coal itself (i.e., the fuel) is abundant and cheap: as shown in **Figure 3**, its price—expressed in dollars for the same energy content, i.e., dollars per million Btu—has sometimes been less than

² North American Electric Reliability Corporation, *2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations*, October 2010, pp. I and IV, http://www.nerc.com/files/EPA_Scenario_Final.pdf. Hereinafter referred to as the "NERC report." NERC is an independent organization, founded by the electric utility industry, that conducts periodic, independent assessments of the reliability and adequacy of the bulk power system in North America.

one-fourth the cost of natural gas, its main competitor. Averaged over a 12-year period, coal cost less than one-third as much as gas.

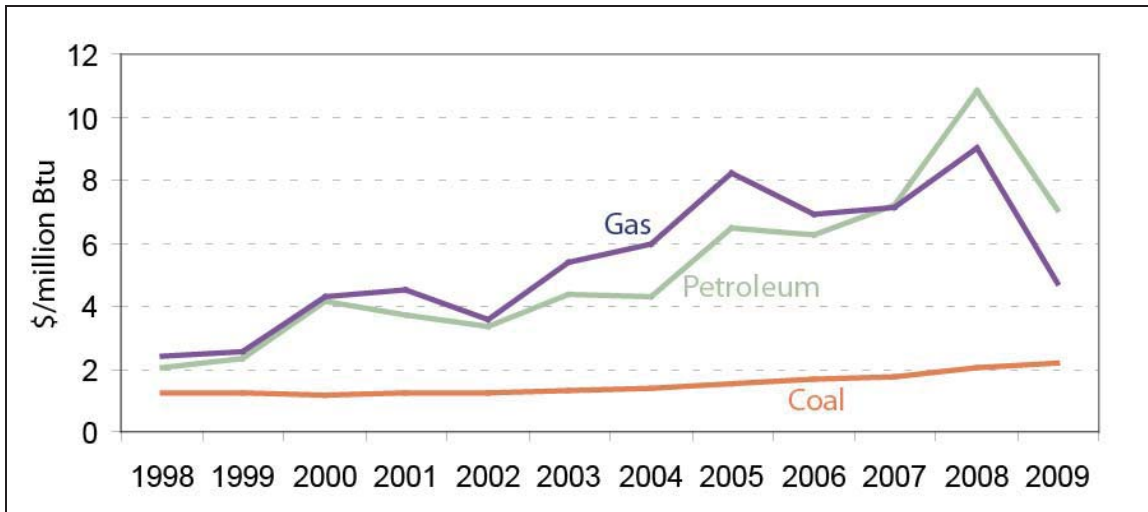
Figure 2. U.S. Electric Power, 2009, by Fuel Type



Source: U.S. Energy Information Administration, *Electric Power Annual, 2009*, April 2011, Table 2.1.

Of course, other factors also affect the price of power, including the efficiency with which the plant converts fuel into electric power, maintenance costs, and the cost of operating the unit—which, in the case of coal must include costs for removal and management of ash. But, in general, these factors did not outweigh coal's basic cost advantage until the advent of natural gas combined cycle technology in the 1990s.

Figure 3. Average Cost of Fossil Fuels for the Electric Power Industry, 1998 through 2009
 (\$/million Btu)

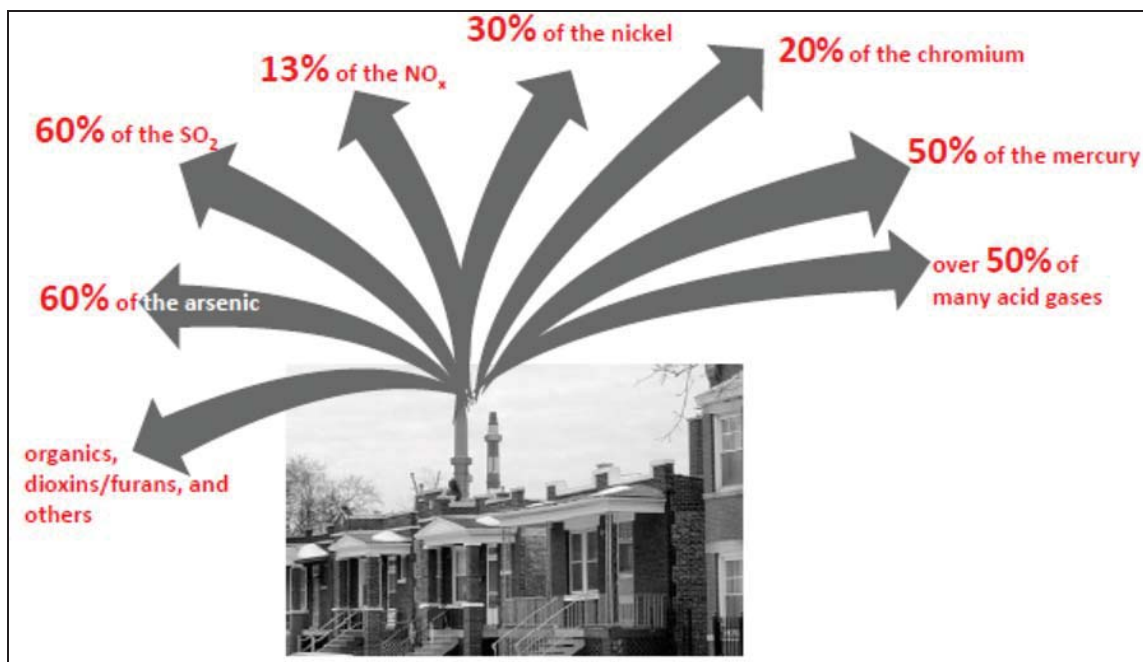


Source: U.S. EIA, Electric Power Annual 2009, April 2011, Table 3.5.

Clean Air Act Exceptions

Besides the age of the plants and the cost of the fuel, a third factor that has resulted in lower cost is that many of the coal-fired plants, particularly the older ones, have been allowed to operate with little in the way of pollution control equipment. Coal is an inherently “dirty” fuel. Burning it produces sulfur dioxide (SO₂), nitrogen oxides (NO_x), particulates, mercury, acid gases, and other pollutants, in greater abundance than other fossil fuels. As shown in **Figure 4**, coal-fired power is a major or *the* major source of the air emissions of many of these pollutants.

Figure 4. Emissions from Fossil-Fueled Power Plants as a Percent of Total U.S. Air Emissions



Source: U.S. EPA, "Reducing Toxic Pollution from Power Plants," March 16, 2011, p. 6.

Note: The figure includes emissions from oil-fired units as well as coal-fired, but oil-fired units account for only 1% of U.S. electric generation. Air emissions are not necessarily the major source of exposure for each of these pollutants.

Despite the industry's emissions, the structure of the Clean Air Act has allowed many of the older coal plants to operate with minimal controls. The statute's focus is on new sources of pollution (including major modifications of existing plants). Under Sections 165 and 169 of the act, new plants and major modifications are required to install the Best Available Control Technology (BACT) in order to obtain an operating permit. Other plants (so-called "grandfathered plants") are not required to have best available controls, unless subject to state or local requirements needed to address local air quality. The majority of the grandfathered plants are coal-fired.

In addition, the act's major requirements for existing power plants, the acid rain program and the NO_x control program (generally known as the "NO_x SIP call"), have both been cap-and-trade programs. These allowed companies to decide how they wanted to meet system-wide emission caps: by switching to lower sulfur fuels, by installing the best control equipment on a few plants, by operating their dirtiest plants less frequently, or by purchasing allowances from facilities that had over-complied. Since controls weren't required on each individual plant, many of the older plants could keep running without them.³

³ Power plant operations also can affect water quality in several ways, and EPA is developing regulations to strengthen requirements for both water intake and water effluent. These regulations affect a broader range of power plants, however, including natural gas and nuclear, as well as coal-fired.

The "Train Wreck" Rules

General Observations

Burning coal to generate electricity can affect the environment in a number of ways, producing air pollution, water pollution, and solid waste residuals. As reflected in the EEI timeline and other analyses, EPA's regulatory activities touch on all of these, although much of the recent critical attention has focused on air pollution.

EEI's chart contains 32 entries covering a 10-year period, 2008-2017. Not all of these entries represent actions by the Obama Administration's EPA. Of the first seven, for example, three are court decisions vacating and remanding Bush Administration EPA rules, and the other four are rules that were promulgated during the Bush Administration with implementation scheduled for 2009 or 2010. Because the Bush Administration's Clean Air Interstate Rule (CAIR) was the subject of two court decisions and was designed to be implemented in phases, it gets numerous entries: three entries for implementation (for its seasonal NO_x cap), its annual NO_x cap, and its SO₂ cap) and two for the court decisions that vacated and remanded it.

CAIR and its replacement rules are the extreme example of repetition on the "train wreck" charts, accounting for 10 of the 32 total entries, but most of the other rules on the chart have at least three entries—for proposal, promulgation, and implementation. Only implementation imposes an actual burden on the regulated community. Thus, the chart tends to exaggerate the regulatory burden through repetition.

The timeline also treats as imminent the promulgation of rules that may not be so. For example, the coal combustion waste rule, which has been the object of some concern, was authorized in the Solid Waste Disposal Act Amendments of 1980. The legislation required that EPA conduct a study of whether such waste should be considered hazardous waste and report to Congress before taking regulatory action. EPA has conducted numerous studies over the three decades since then and proposed to regulate the management of the waste in June 2010. Since then, however, the agency has stated that it does not anticipate promulgating a final rule in 2011, leaving uncertain when a rule will be promulgated. The EEI timeline assumed promulgation in 2011 with compliance five years later.

Nevertheless, it is safe to say that several major rules under development at EPA are due to be promulgated within the next 18 months and will affect coal-fired power plants, as shown in **Table 1**. Some of them are expected to be expensive; the costs of others are likely to be moderate or limited, or they are unknown at this point because a rule has not yet been proposed.

Table I. Timing of EPA Rules and Impacts on Coal-Fired Utilities

Rule or Standard	Final Rule	EPA Estimate of Costs/Impacts ^a
Cross-State Air Pollution Rule	Finalized July 6, 2011	\$2.4 billion/year ^b
Utility MACT Rule	Expected November 16, 2011	\$10-\$11 billion/year
National Ambient Air Quality Standard (NAAQS) for sulfur dioxide	Promulgated June 22, 2010	\$1.5 billion/year for all sources, but limited impact on electric generating units (EGUs) ^a
NAAQS for ozone	Expected July 2011	\$19-\$25 billion/year for all sources but limited impact on EGUs ^a
NAAQS for particulate matter	Not yet proposed; expected in 2012	Unknown
New Source Performance Standards for Greenhouse Gases	Not yet proposed; expected May 26, 2012	Unknown
Cooling Water Intake Structure Rule	Expected July 27, 2012	\$319 million/year
Clean Water Effluent Limitation Guidelines Rule	Not yet proposed; expected January 31, 2014	Unknown
Coal Combustion Waste Rule	Expected 2012 or later	\$587 million-\$1.5 billion/year

Source: Compiled by CRS.

- a. Costs as estimated by EPA. See text for discussion of costs and impacts of specific rules.
- b. Of the \$2.4 billion annual cost, \$1.6 billion is attributed to the Clean Air Interstate Rule (CAIR), a 2005 rule that the Cross-State Rule is replacing.

This report will discuss each of the rules identified on EEI's timeline individually; but before discussing individual rules, a few general statements are in order.

First, most of these rules have been a long time in the making. As noted, the coal combustion waste rule is the result of legislation passed in 1980; another rule, the utility air toxics rule (or "Utility MACT"), which appears to be the most costly of the rules thus far proposed, is required by the Clean Air Act Amendments of 1990. Some may question why EPA is undertaking so many regulatory actions at once, but it is the decades of regulatory inaction that led to this point that strike other observers.

The inaction stemmed in large part from special consideration given electric utilities by Congress: both the Clean Air Act and the Solid Waste Disposal Act required special studies and reports to Congress before EPA could set standards for certain pollutants emitted or wastes disposed by electric utilities. Meanwhile, other industries that emitted the same pollutants or similar wastes (e.g., municipal solid waste incinerators and medical waste incinerators, and any industry generating hazardous waste) have been subject to more stringent emission controls or waste management standards for a decade or more.

Second, as we have noted in an earlier report on EPA regulations,⁴ both the legislative authority for these rules and, in most cases, the development of the rules themselves predate the current Administration. With the exception of greenhouse gas emission rules, all of the rules discussed below began development under the Bush Administration or earlier, including several that were promulgated under that Administration and subsequently were vacated or remanded to EPA by the courts. The Cross-State Air Pollution Rule, the Utility MACT rule, and the Cooling Water Intake rule, for example, fit that description. Other EPA actions, such as the Obama Administration's reconsideration of the ozone National Ambient Air Quality Standard, have actually delayed for several years implementation of Bush Administration rules that would have strengthened existing standards. Each of these actions is described in more detail below.

Third, one criticism highlighted by the EEI and others of EPA's pending and upcoming rules is the impact of multiple requirements. The critics point out that, although EPA conducts detailed economic impact analyses of individual rules, the CAA and other federal environmental laws do not provide a mechanism or require that the agency analyze cumulative impacts, including jobs. Viewed separately, they argue, a particular rule may have limited economic impact, while the second, third, or fourth rule that takes effect more or less simultaneously may drive the power plant operator to decide to retire a given facility. As discussed in this report, such decisions are highly case-specific, involving unique considerations and potentially mitigating factors.

The following sections of this report describe seven rules or categories of rules that are the core of the "train wreck" debate, with background on the rule, information on its requirements (for those rules that have been proposed or promulgated), and where possible, a discussion of the rule's potential costs and benefits. We also examine two of the studies—those of the electric industry's trade association (EEI) and the North American Electric Reliability Corporation—that have attempted to estimate their cumulative economic impacts.

Cross-State Air Pollution (Clean Air Transport) Rule

The Cross-State Air Pollution Rule (hereinafter, the "Cross-State Rule") replaces EPA's major clean air initiative under the Bush Administration, the Clean Air Interstate Rule (CAIR). CAIR was promulgated in 2005, but was vacated and remanded to the agency by the D.C. Circuit Court of Appeals in 2008.⁵ On appeal, the court left the rule in place until such time as EPA promulgated a replacement. The agency proposed the replacement August 2, 2010,⁶ and it finalized the rule July 6, 2011.⁷

⁴ CRS Report R41561, *EPA Regulations: Too Much, Too Little, or On Track?*, by James E. McCarthy and Claudia Copeland.

⁵ The promulgated rule was published at 70 *Federal Register* 25162, May 12, 2005. The court decision was *North Carolina v. EPA*, 531 F.3d 896 (D.C. Cir. 2008).

⁶ U.S. Environmental Protection Agency, "Federal Implementation Plans To Reduce Interstate Transport of Fine Particulate Matter and Ozone; Proposed Rule," 75 *Federal Register* 45210, August 2, 2010.

⁷ The final rule has not appeared in the *Federal Register* as of this writing, but a pre-publication copy as well as explanatory and background material can be found on EPA's website at <http://www.epa.gov/crossstaterule/actions.html>. When proposed in August 2010, the Cross-State Rule was referred to as the Clean Air Transport Rule. The name change to "Cross-State Rule" occurred late in the development of the final rule. As a result, many of the explanatory materials, including the final Regulatory Impact Analysis, refer to the "Transport Rule."

Both CAIR and its replacement, the Cross-State Rule, are designed to control emissions of air pollution that cause air quality problems in downwind states. The original, Bush-era rule did so by establishing region-wide cap-and-trade programs⁸ for SO₂ and NO_x emissions from coal-fired electric power plants in 28 Eastern states, at an estimated annual compliance cost of \$3.6 billion in 2015.⁹ CAIR covered only the eastern half of the country, but since most of the coal-fired generation capacity lacking emission controls is located there, EPA projected that nationwide emissions of SO₂ would decline 53% and NO_x emissions 56% by 2015, as compared to nationwide emissions from electric generating units (EGUs) in 2001.

The replacement rule, finalized July 6, 2011, is a modified cap-and-trade rule. It would allow unlimited trading of allowances within individual states; interstate trading would be allowed so long as a state remained within 18%-21% of its emissions caps. Limiting interstate trading would address the D.C. Circuit's ruling, which found CAIR's interstate allowance trading program unlawful.

The rule applies to 28 states (adding Oklahoma, Kansas, and Nebraska to the 28 covered by CAIR, but removing Connecticut, Delaware, and Massachusetts from the CAIR group). Its annual compliance cost is estimated at \$3.0 billion in 2012 and \$2.4 billion in 2014.¹⁰

The Cross-State Rule would leave the CAIR Phase 1 (2009-2010) caps in place and would set new limits replacing CAIR's second phase in 2012 and 2014, up to three years earlier than CAIR would have done. The 2012 and 2014 requirements place particular emphasis on SO₂—emissions of which would decline to 2.4 million tons in the covered states (73% below 2005 levels) in 2014.

To insure that the Cross-State Rule is implemented quickly, EPA is promulgating a Federal Implementation Plan (FIP) for each of the states: the FIP specifies emission budgets for each state based on controlling emissions from electric power plants. States may develop their own State Implementation Plans and may choose to control other types of sources if they wish, but the federal plan will take effect until the state acts to replace it.

The CAIR Phase 1 rules already appear to be having substantial effects. In August 2010, EPA reported that emissions of SO₂ had declined sharply in both 2008 and 2009: in the latter year, emissions from fossil-fueled power plants in the lower 48 states (at 5.7 million tons) were 44% below 2005 levels. NO_x emissions from the same sources declined to 1.8 million tons in 2009, a

⁸ A cap-and-trade system sets a declining national cap on emissions and allocates emission allowances that can be bought and sold on open markets.

⁹ 70 *Federal Register* 25306, May 12, 2005.

¹⁰ These cost estimates include \$1.6 billion in annualized costs already incurred to comply with Phase 1 of CAIR. EPA estimates the additional cost of the Cross-State Rule at \$1.4 billion in 2012 and \$0.8 billion in 2014. The 2014 cost of compliance with the Cross-State is less than that estimated for 2012 or for final implementation of CAIR in 2015 because the Regulatory Impact Analyses for the two rules use different base years for comparison. As the agency's RIA for the Cross-State Rule notes, "The base case in this RIA assumes that CAIR is not in effect, but does take into account emissions reductions associated with the implementation of all federal rules, state rules and statutes, and other binding, enforceable commitments finalized by December 1, 2010, that are applicable (sic) the power industry and which govern the installation and operation of SO₂ and NO_x emissions controls in the timeframe covered in the analysis." Thus, the base with which control requirements are compared already accounts for some reductions realized since the original CAIR rule was promulgated. See U.S. EPA, Office of Air and Radiation, *Regulatory Impact Analysis (RIA) for the final Transport Rule*, June 2011, p. 244, at <http://www.epa.gov/crossstaterule/pdfs/FinalRIA.pdf>. Hereafter, "Cross-State Rule RIA."

decline of 45% compared to 2005.¹¹ The reductions occurred well in advance of CAIR's compliance dates: in fact, for both SO₂ and NO_x, the affected units had achieved about 80% of the required 2015 reductions six years ahead of that deadline. Further reductions of both SO₂ and NO_x can be expected as Phase 1 takes effect. The Cross-State Rule would build on these reductions.

As noted earlier, EPA estimated that compliance with the rule will cost the power sector \$2.4 billion annually when fully effective. It expects the benefits to be 50 to almost 120 times as great—an estimated \$120 billion to \$280 billion annually. The most important benefit would be 13,000 to 34,000 fewer premature deaths annually. Avoided deaths and other benefits would occur throughout the East, Midwest, and South, according to EPA, with Ohio and Pennsylvania benefitting the most.¹²

Both EEI and NERC included the Cross-State Rule in their analyses, and their estimates of the rule's cost and the impact on coal-fired power do not appear to differ greatly from those of EPA, particularly in the "train wreck" years, from now until 2017. NERC, for example, concluded that the Cross-State Rule as proposed (then referred to as the "Transport Rule") would lead to 2.9 GW of deratings¹³ or retirements by 2015.¹⁴ This would represent less than 1% of coal-fired capacity, and less than 0.3% of all EGU capacity. EPA, by comparison, projects that 4.8 GW of coal-fired capacity would be uneconomic to maintain as a result of the rule.¹⁵

EEI's analysis stated that it used EPA's Integrated Planning Model assumptions with "no additional controls for SO₂-specific compliance" and with EPA's preferred option for NO_x compliance through 2017. With the same assumptions and the same model, EEI's projected compliance costs should not differ from those of EPA.

For the years after 2017, however, EEI's analysis did differ from that of EPA: it assumed that selective catalytic reduction (SCR) would be required on all units to reduce NO_x emissions. This *would* impose additional cost, since about 54% of coal-fired capacity will not have installed SCR to comply with the Cross-State Rule's 2014 requirements, according to EPA.¹⁶ These costs are speculative: to date, EPA has not proposed additional post-2014 requirements, and, as a result, the agency has not estimated costs of compliance or a schedule for implementation of any future pollution transport regulations.¹⁷

¹¹ Data are from EPA's "2009 Acid Rain Program Emission and Compliance Data Report," August 11, 2010, at <http://www.epa.gov/airmarkets/progress/ARP09.html>. Some of the emission reduction was the result of the recession, which resulted in a decline in electric power generation of 5% from 2007 to 2009. Coal use for electricity generation declined even more (11% from 2007 to 2009).

¹² U.S. EPA, Office of Air and Radiation, "Final Air Pollution Cross-State Air Pollution Rule," Overview Presentation, undated, pp. 12-14, at <http://www.epa.gov/crossstaterule/pdfs/CSAPRPresentation.pdf>.

¹³ "Derating," in these analyses, refers to the loss of available capacity because of the power needed to operate the pollution control equipment.

¹⁴ NERC report, p. 20.

¹⁵ Cross-State Rule RIA, p. 262.

¹⁶ Cross-State Rule RIA, p. 259.

¹⁷ Given the need to meet the more stringent ambient air quality standard (NAAQS) requirements, especially those for ozone and PM (described below), which EPA is expected to propose or promulgate this year, the agency stated its intention to propose a further set of requirements addressing interstate transport of air pollution in 2011. (These potential further rules appear on EEI's chart as "Transport Rule II (NO_x) Proposal" and "PM Transport Rule.")

To summarize, CAIR and its replacement, the Cross-State Air Pollution Rule, would impose annual costs in the \$2 billion to \$3 billion range on previously uncontrolled coal-fired electric generating units. Although these are significant costs, the industry has already complied with Phase 1, which was the most ambitious of the rules' requirements. Prompted by the ability to generate tradable allowances, the industry complied well ahead of schedule. The final version of the Cross-State Rule allows additional allowance trading as compared to the proposed rule, giving EGUs additional flexibility in determining how to comply and lowering compliance costs.

Mercury and Air Toxics Standards/Utility MACT

In 2005, EPA promulgated regulations establishing a cap-and-trade system to limit emissions of mercury from coal-fired power plants. Coal-fired electric generating units (EGUs) account for about half of U.S. mercury emissions. Mercury is a potent neurotoxin that can harm health (principally delayed development, neurological defects, and lower IQ in fetuses and children) at very low concentrations.¹⁸

The mercury cap-and-trade rules promulgated in 2005 were a change in policy by EPA. All previous sources of mercury subject to emission standards had been required to meet plant-specific Maximum Achievable Control Technology (MACT) standards under CAA Section 112.¹⁹ Section 112 sets out very detailed requirements for MACT standards, including a list of the pollutants that need to be controlled (not just mercury, but any of 187 hazardous air pollutants, or HAPs) and the level of control that the standards must achieve. The 2005 cap-and-trade rules addressed only mercury, and would have allowed many power plants to avoid control provided they obtained allowances from others who achieved lower pollution levels than required, or reduced emissions sooner than required. The ability of plants to avoid emission control by purchasing allowances could lead to the continuation of "hot spots," areas where mercury concentrations in waterbodies are greater than elsewhere.

By contrast, the statute requires MACT standards applicable at each existing plant to be no less stringent than the average emission limitation achieved by the best performing 12% of existing sources in the industry subcategory.²⁰ These statutory requirements are referred to as the "MACT floor," because the agency is not allowed to set less stringent standards, nor may it take economic factors into account in determining what the floor will be.

Whether the agency could substitute cap-and-trade rules for the MACT requirements was challenged by the State of New Jersey and others, and, in a 3-0 decision, the D.C. Circuit Court of Appeals vacated the cap-and-trade rules in 2008.²¹ The court found that, under Section 112,

¹⁸ The principal route of exposure to mercury is through consumption of fish. Mercury enters water bodies, often through air emissions, and is taken up through the food chain, ultimately affecting humans as a result of fish consumption. All 50 states have issued fish consumption advisories due to mercury pollution, covering 16.8 million acres of lakes, 1.25 million river miles, and the coastal waters of 20 entire states. For a more detailed discussion of mercury's health effects, see CRS Report RL32420, *Mercury in the Environment: Sources and Health Risks*, by Linda-Jo Schierow. For EPA's "2008 Biennial National Listing of Fish Advisories," September 2009, see http://water.epa.gov/scitech/swguidance/fishshellfish/fishadvisories/upload/2009_09_16_fish_advisories_tech2008.pdf.

¹⁹ EPA identified 174 industrial categories to be regulated under the MACT provisions. Standards have been promulgated for almost all these categories except EGUs.

²⁰ For new sources, the standards are to be based on the emission control achieved by the best controlled similar source.

²¹ *New Jersey v. EPA*, 517 F.3d 574 (D.C. Cir. 2008).

unless EPA "delisted" the category of sources, it had to require that each plant in the category meet MACT standards. Under the statute, delisting would have required a finding that no EGU's emissions exceeded a level adequate to protect public health with an ample margin of safety, and that no adverse environmental effect would result from any source.

Rather than appeal the court's ruling to the Supreme Court or attempt to delist the category, EPA proposed what is referred to as the "Utility MACT," March 16, 2011.²² The proposal appeared in the *Federal Register* May 3, beginning a public comment period that runs through August 4. Under a consent agreement, the final MACT standards are to be promulgated by November 16, 2011.

The Proposed Rule

As proposed, the Utility MACT would require coal-fired power plants to achieve a 91% reduction from uncontrolled emissions of mercury, nine other toxic metals, and three acid gases, all of which were listed by Congress as hazardous air pollutants in the 1990 Clean Air Act Amendments. Power plants are the largest emitters of many of these pollutants, accounting for about 50% of the nation's mercury emissions, 62% of arsenic emissions, and 82% of hydrochloric acid emissions, for example.²³ The Utility MACT would also reduce emissions of fine particulates (PM_{2.5}), which, although not categorized as hazardous air pollutants, are estimated to cause thousands of premature deaths annually.

In proposing the standards, EPA noted that while the requirements are stringent for those facilities lacking controls, 56% of existing coal-fired power plants already are in compliance. Thus, the standards are expected to level the playing field, bringing older, poorly controlled plants up to the standards being achieved by a majority of the existing units. In this respect, the proposed standards reflect the statute's requirement that existing sources of HAPs should meet standards based on the current emissions of the best performing similar sources.

The agency also concluded that some plants, representing less than 10 GW of coal-fired capacity, will be retired by 2015, rather than invest in control technologies. In all, it said, coal-fired generation will decline about 2% compared to estimated generation in the absence of the rule.²⁴

Costs, Benefits, and Control Technology

EPA projected the annualized cost of compliance with the proposed rule at \$10.9 billion in 2015, and remaining at \$10 billion - 11 billion annually through 2030.²⁵ The average consumer would see an increase of \$3-\$4 per month in the cost of electricity due to the rule, according to the agency.²⁶ These costs will go largely to the installation of scrubbers and fabric filters. As a result

²² For a link to the proposed rule as well as explanatory material, see U.S. EPA, "Reducing Toxic Air Emissions from Power Plants," at <http://www.epa.gov/airquality/powerplanttoxics/actions.html>.

²³ See U.S. EPA, "Emissions Overview: Hazardous Air Pollutants in Support of the Proposed Toxics Rule," Memorandum from Madeleine Strum, Emission Inventory and Analysis Group, to Marc Houyoux, Group Leader, Emission Inventory and Analysis Group, March 15, 2011, Tables 3 and 4.

²⁴ U.S. EPA, *Regulatory Impact Analysis of the Proposed Toxics Rule: Final Report*, March 2011, p. 8-17 at <http://www.epa.gov/ttn/ecas/regdata/RIAs/ToxicsRuleRIA.pdf>. Hereafter, "Utility MACT RIA."

²⁵ Utility MACT RIA, p. 8-12.

²⁶ U.S. EPA, "Power Plant Mercury and Air Toxics Standards: Overview of Proposed Rule and Impacts," p. 3, at (continued...)

of the rule, 26 GW of coal-fired units, about 9% of total coal-fired capacity, are expected to install scrubbers. (EPA estimated that by the time the rule requires compliance, 203 GW will already have installed scrubbers anyway, as a result of other regulations.)²⁷

More than half of the coal-fired EGU capacity (166 GW) are expected to add fabric filters because of the rule, while 77 GW would have them whether or not there were a rule. In most cases, the fabric filters will be coupled with activated carbon injection or dry sorbent injection.²⁸ Mercury and other HAPs become attached to the carbon or sorbent after it is injected into the flue gas, and the fabric filter collects the particles, removing them from the plant's emissions. EPA estimates that 62 GW of coal-fired capacity (about one-fifth of the U.S. total) would have either activated carbon or dry sorbent injection in 2015 without the rule. The rule adds another 149 GW of carbon/sorbent installations.

This is not complicated or new technology. Other types of facilities (notably solid waste incinerators) have used this technology for the past 15 years to reduce their mercury and other HAP emissions by 95% or more. As a result of state-level pollution control regulations, a growing percentage of coal-fired power plants do the same.

The benefits of the rule are estimated by EPA at \$59 billion to \$140 billion annually—5 to 13 times as great as the costs—due primarily to the avoidance of 6,800 to 17,000 premature deaths each year.²⁹ Other benefits, only some of which were given dollar values, include the annual avoidance of 11,000 nonfatal heart attacks, 120,000 cases of aggravated asthma, and developmental effects on children, including effects on IQ, learning, and memory.³⁰

Of the proposed EPA rules, the Utility MACT is probably the most costly and most likely to affect older coal-fired plants that have not yet installed current pollution control technology. EPA's proposal does allow averaging of emissions from multiple units at a single location, which may allow some older units that are operated infrequently to remain in service, but the absence of broader allowance trading provisions in the law and the stringency of the emission requirements mean that most units will not be able to escape regulation.

EEI's and NERC's Analyses of the Utility MACT Rule

In its report, which was written before EPA's Utility MACT proposal, EEI concluded that, "All coal units [would be] required to install a scrubber (wet or dry), activated carbon injection (ACI) and a baghouse/fabric filter" for compliance with the MACT.³¹ This goes well beyond what EPA proposed. Compared to EPA's projections, it concluded that five times as much scrubber capacity, nearly three times as much ACI, and about one and one-half times as much baghouse capacity

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<http://www.epa.gov/airquality/powerplanttoxics/pdfs/overviewfactsheet.pdf>

²⁷ U.S. EPA, "Reducing Toxic Pollution from Power Plants: EPA's Proposed Mercury and Air Toxics Standards," Overview Presentation, March 16, 2010, p. 15, <http://www.epa.gov/airquality/powerplanttoxics/pdfs/presentation.pdf>.

²⁸ Ibid.

²⁹ Ibid., p. 13.

³⁰ U.S. EPA, "Fact Sheet: Proposed Mercury and Air Toxics Standards," March 2011, p. 3, at <http://www.epa.gov/airquality/powerplanttoxics/pdfs/proposalfactsheet.pdf>. For additional information, see Utility MACT RIA, pp. 1-2 to 1-10, and Chapter 5.

³¹ EEI report, p. 43.

would need to be added, making the rule substantially more costly and far more difficult to comply with in the limited time provided by the statute.

NERC's report, which was also written before EPA proposed the Utility MACT, also assumed that vastly more pollution control equipment would need to be added to coal-fired plants than EPA believes will be necessary. The NERC analysis assumed wet scrubbers would be added to all coal-fired plants that don't already have them, that selective catalytic reduction (SCR) will be added to all bituminous coal-powered facilities, and that activated carbon injection and baghouses would be added at all facilities burning other types of coal.³² These assumptions are similar to EEI's except that by assuming wet scrubbers (instead of EPA's general assumption that dry scrubbers will suffice) and by assuming SCR at bituminous facilities, the cost impacts would most likely be even greater than the costs in EEI's assessment.³³ NERC concluded that 8.4 GW to 17.6 GW of capacity would be retired or derated as a result of the MACT rule. If fewer units need controls and less expensive pollution control equipment is needed on those that do, the retirements and deratings would be fewer.

Following promulgation of these standards, existing power plants will have three years, with a possible one-year extension, to meet the standards. (The three-to-four-year timeframe is mandated by the statute.) Many in industry argue that three or four years is not enough time to complete the required pollution control equipment installation, and as a result that the reliability of the nation's electric power supply could be affected by the rule. NERC did not say this directly, in part because its analysis combines the effects of four rules, making it difficult to disaggregate the Utility MACT's effect. What it did say was:

The MACT Rule considered alone could drive Planning Reserve Margins of 8 regions/subregions below the NERC Reference Margin Levels standards and trigger the retirement of 2-15 GW ... of existing coal capacity by 2015. To comply, owners of the remaining capacity need to retrofit from 277 to 753 units with added environmental controls. The "hard stop" 2015 compliance deadline proposed by the MACT Rule makes retrofit timing a significant issue and potentially problematic.³⁴

In part, whether or not there is sufficient time to implement the rule without threatening electric system reliability will depend on the number of units that require retrofits. EPA is the only one of the three sources discussed herein that analyzed the actual proposal. Both EEI and NERC assumed requirements that appear to be substantially more stringent than what EPA proposed. If EPA is correct in its analysis, the number of retrofits appears to be within the range of what the industry has accomplished in the past as a result of earlier regulations. This point is discussed below in more detail, under "Train Wreck?"

New Source Performance Standards for Greenhouse Gas Emissions

On December 23, 2010, EPA released the text of a settlement agreement with 11 states, two municipalities, and three environmental groups, under which it agreed to propose New Source Performance Standards (NSPS) to address greenhouse gas emissions from power plants by July 26, 2011, and take final action on the proposal by May 26, 2012. (The agency recently announced

³² NERC report, p. 50.

³³ For a detailed comparison of equipment cost, see EEI report, p. 33.

³⁴ NERC report, p. V.

that it will delay proposal until September 30, 2011, but it expects to retain the May 26, 2012 date for final action.) Electric generating units are the largest U.S. source of greenhouse gas (GHG) emissions, accounting for about one-third of total U.S. emissions. Coal-fired plants accounted for 81% of the electric power industry's total GHG emissions in 2009³⁵ and, thus, are expected to be the main focus of EPA's NSPS rules.

New Source Performance Standards are emission limitations imposed on designated categories of major new (including substantially modified) stationary sources of air pollution. CAA Section 111 gives EPA authority to set NSPS for emissions of "air pollutants," a term that includes greenhouse gases.³⁶ A new source is subject to NSPS regardless of its location (i.e., the same standards apply to all new and modified major facilities anywhere in the United States). The statute provides authority for EPA to impose such standards directly in the case of new (or modified) sources (Section 111(b)), and through the states in the case of existing sources (Section 111(d)). The authority to impose performance standards on new and modified sources refers to any category of sources that the EPA Administrator judges "causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare" (Sec. 111(b)(1)(A))—language similar to the endangerment and cause-or-contribute findings EPA used to promulgate GHG emission standards for motor vehicles in 2010.

In establishing these standards, Section 111 gives EPA considerable flexibility with respect to the source categories regulated, the size of the sources regulated, and the particular gases regulated, along with the timing and phasing in of regulations. This flexibility extends to the stringency of the regulations with respect to costs and secondary effects, such as non-air-quality, health and environmental impacts, along with energy requirements. This flexibility is encompassed within the Administrator's authority to determine the control systems that have been "adequately demonstrated." Standards of performance developed by the states for existing sources under Section 111(d) can be similarly flexible.

Assuming EPA promulgates the greenhouse gas NSPS on schedule, how quickly such standards would be applied to existing sources is an open question. EPA must first propose and promulgate guidelines, following which the states would be given time to develop implementation plans.³⁷ Following approval of the plans, the act envisions case-by-case determinations of emission limits, in which the states may consider, among other factors, the remaining useful life of a source in setting an emission limit. Thus, it is likely to be several years before existing power plants are subject to emission limits for GHGs.

Since EPA has not yet proposed NSPS, the agency has not provided a Regulatory Impact Analysis or cost estimate for such a rule.³⁸ EEI, on the other hand, in six of the nine scenarios in its

³⁵ U.S. EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009*, April 2011, Table 2-13, available at <http://epa.gov/climatechange/emissions/usinventoryreport.html>.

³⁶ In *Massachusetts v. EPA* (549 U.S. 497 (2007)), the Supreme Court held, in a 5-4 decision, that greenhouse gases are clearly air pollutants under the Clean Air Act's definition of that term.

³⁷ How much time the states would be given to submit plans is unclear. The statute says that the regulations shall establish a procedure "similar to that" provided for State Implementation Plans under Section 110, which generally give states three years to submit a plan, following which EPA reviews it to determine its adequacy.

³⁸ Agency guidance for state GHG permitting decisions, issued in November 2010, is perhaps the best example of what the agency might require: the guidance focuses on energy efficiency as the best available control technology, and states that both conversion to natural gas and carbon capture and sequestration can be eliminated from consideration. While cost is not estimated in the guidance, the requirements would not appear to be stringent. For a discussion of EPA's guidance, see CRS Report R41505, *EPA's BACT Guidance for Greenhouse Gases from Stationary Sources*, by Larry (continued...)

analysis, assumed there would be CO₂ regulations in place by 2017. In five of the scenarios, it estimated the cost of CO₂ regulation or legislation at \$25 per ton of emissions in 2017, with price escalation of 5% annually thereafter. This assumption would impose a larger burden on coal-fired power plants than any of the other rules considered in EEI's report. In 2009, coal-fired electric power plants emitted 1,748 million tons of CO₂.³⁹ Assuming roughly the same level of emissions in 2017, EEI's \$25/ton assumption would result in a cost of CO₂ regulation of \$43.7 billion in 2017, with 5% increases each year thereafter. This cost, which appears to have been based on its analysis of legislation not enacted in the 111th Congress, dwarfs every other projected regulatory cost in the regulatory impact analyses that CRS examined. Inclusion of this requirement leads, in EEI's analysis, to an additional 23 GW of retired capacity in 2015 and 40 GW of incremental retirements in 2020, accounting for more than half of all retirements in the latter year.⁴⁰

NERC, on the other hand, did not include CO₂ regulation in its study.

NAAQS Revisions

EPA is required in CAA Sections 108 and 109 to set National Ambient Air Quality Standards (NAAQS) for air pollutants that endanger public health ("primary" NAAQS) or welfare ("secondary" NAAQS) and that are emitted by numerous or diverse sources. NAAQS do not directly regulate emissions. Rather, the primary NAAQS identify pollutant concentrations in ambient air that must be attained to protect public health with an adequate margin of safety. Secondary NAAQS identify concentrations necessary to protect public welfare, a broad term that includes damage to crops, vegetation, property, building materials, and more.

In essence, NAAQS are standards that define what EPA considers to be clean air. Their importance stems from the long and complicated implementation process that is set in motion by their establishment. Once NAAQS have been set, EPA, using monitoring data and other information submitted by the states to identify areas that exceed the standards and must, therefore, reduce pollutant concentrations to achieve them. State and local governments then have three years to produce State Implementation Plans which outline the measures they will implement to reduce the pollution levels in these "nonattainment" areas. Nonattainment areas are given anywhere from three to 20 years to attain the standards, depending on the pollutant and the severity of the area's pollution problem.

EPA also acts to control many of the NAAQS pollutants wherever they are emitted through national standards for certain products that emit them (particularly mobile sources, such as automobiles) and emission standards for new stationary sources, such as power plants.

In the 1970s, EPA identified six pollutants or groups of pollutants for which it set NAAQS.⁴¹ But that was not the end of the process. When it gave EPA the authority to establish NAAQS, Congress anticipated that the understanding of air pollution's effects on public health and welfare

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Parker and James E. McCarthy.

³⁹ U.S. EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009*, April 2011, Table 2-13, available at <http://epa.gov/climatechange/emissions/usinventoryreport.html>.

⁴⁰ EEI report, p. v.

⁴¹ The six pollutants are ozone, particulates, carbon monoxide, SO₂, NO_x, and lead.

would change with time, and it required that EPA review the standards at five-year intervals and revise them, as appropriate.

The agency is currently conducting the required reviews of these standards: it has already completed reviews for five of the six standards, but two of them have been remanded by the D.C. Circuit Court of Appeals for further agency action, and others are being challenged in court. The electric power industry and others are following this process closely, because more stringent standards could begin a process that would lead to more stringent emission standards.⁴²

The three standards most likely to affect power plants are those for SO₂, ozone, and particulate matter (PM).

Sulfur Dioxide (SO₂)

On June 22, 2010, EPA revised the NAAQS for SO₂, focusing on short-term (1-hour) exposures. The prior standards (for 24-hour and annual concentrations), which were set in 1971, were revoked as part of the revision. Since 1971, EPA had conducted three reviews of the SO₂ standard without changing it. However, following the last of these reviews, in 1998, the D.C. Circuit Court of Appeals remanded the SO₂ standard to EPA, finding that the agency had failed adequately to explain its conclusion that no public health threat existed from short-term exposures to SO₂.⁴³ Twelve years later, EPA revised the standard to respond to the court's decision.

The new short-term standard is substantially more stringent than the previous standards: it replaces a 24-hour standard of 140 parts per billion (ppb) with a 1-hour maximum of 75 ppb. This means that there could be an increase in the number of SO₂ nonattainment areas (especially since there were *no* nonattainment areas under the old standards), with additional controls required on the sources of SO₂ emissions in any newly designated areas. Since electric generating units accounted for 60% of total U.S. emissions of SO₂ in 2009, additional controls on EGUs would be likely.

The timing and extent of any additional controls is uncertain, however, for several reasons. First, the monitoring network needed to determine attainment status is incomplete and is not primarily configured to monitor locations of maximum short-term SO₂ concentrations.⁴⁴ The agency says it will need 41 new monitoring sites to supplement the existing network in order to have a more complete data base. Since three years of data must be collected after a site's startup to determine attainment status, it may be as late as 2016 before some areas will have sufficient data to be classified. Even if the areas can be designated sooner based on modeling data, it would be at least 2015 before State Implementation Plans with specific control measures would be due, and actual compliance with control requirements would occur several years later.

Meanwhile, SO₂ emissions will be significantly reduced as a result of the CAIR, Cross-State, and Utility MACT rules described above. Thus, although EPA identified 59 counties that would have

⁴² Five of the entries on EEI's "train wreck" chart (**Figure 1**) refer to NAAQS reviews.

⁴³ American Lung Association v. EPA, 134 F.3d 388 (D.C. Cir 1998).

⁴⁴ U.S. EPA, "Fact Sheet: Revisions to the Primary National Ambient Air Quality Standard Monitoring Network, and Data Reporting Requirements for Sulfur Dioxide," June 2, 2010, p. 3, at <http://www.epa.gov/air/sulfurdioxide/pdfs/20100602fs.pdf>.

violated the new SO₂ NAAQS based on 2007-2009 data, it is not clear whether any of these counties will be in nonattainment by the time EPA designates the nonattainment areas.

In its Regulatory Impact Analysis of the SO₂ NAAQS, the agency estimated that attainment would require a reduction of 370,000 tons of SO₂ by 2020, about two-thirds of which would need to come from EGUs.⁴⁵ The agency estimated the annualized cost of these controls (for all sources, not just EGUs) at \$1.5 billion. Benefits would range from \$15 billion to \$37 billion annually.⁴⁶

These costs and benefits do not take account of CAIR, the Cross-State Rule, or the Utility MACT, however. (As may be recalled, the CAIR and Cross-State Rules will result in more than 6 million tons of SO₂ emission reductions by 2014.) The agency assumed for purposes of analysis that none of these rules was in effect, because none of them was in effect in 2005, the base year used for analytical purposes. As the agency's RIA states:

The baseline for this analysis is complicated by the expected issuance of additional air quality regulations. The SO₂ NAAQS is only one of several regulatory programs that are likely to affect EGU emissions nationally in the next several years. We thus expect that EGUs will apply controls in the coming years in response to multiple rules. These include the maximum achievable control technology (MACT) rule for utility boilers, revisions to the Clean Air Interstate Rule, and reconsideration of the Clean Air Mercury Rule. Therefore controls and costs attributed solely to the SO₂ NAAQS in this analysis will likely be needed for compliance with other future rules as well.⁴⁷

In short, compared to the Utility MACT and the Cross-State Rule, the SO₂ NAAQS has relatively little impact on coal-fired power plants in EPA's analysis, and the agency's analysis relied on assumptions that probably overstate the impact of the standard.

EEI included the SO₂ NAAQS on its "train wreck" timeline, but neither EEI nor NERC considered the standard in their analyses.

Ozone

On January 19, 2010, EPA proposed a revision of the NAAQS for ozone.⁴⁸ EPA currently expects to finalize this revision by the end of July 2011 (although it has already postponed the review's completion date three times). As noted above, NAAQS do not directly limit emissions, but they set in motion a process under which "nonattainment areas" are identified and states and EPA develop plans and regulations to reduce pollution in those areas.

Ozone is not directly emitted by coal-fired power plants (or most other sources). It forms in the atmosphere as the result of a chemical reaction between nitrogen oxides (NO_x), volatile organic compounds (VOCs), and carbon monoxide (CO) in the presence of sunlight. Power plants emit

⁴⁵ U.S. EPA, Office of Air Quality Planning and Standards, *Final Regulatory Impact Analysis (RIA) for the SO₂ National Ambient Air Quality Standards (NAAQS)*, June 2010, page ES-7, Table ES.2, at <http://www.epa.gov/ttnecas1/regdata/RIAs/fso2ria100602full.pdf>.

⁴⁶ *Ibid.*, p. ES-9, Table ES.4.

⁴⁷ *Ibid.*, p. ES-3.

⁴⁸ U.S. Environmental Protection Agency, "National Ambient Air Quality Standards for Ozone; Proposed Rule," 75 *Federal Register* 2938, January 19, 2010.

one of these precursor emissions, NO_x. Thus, the setting of a more stringent ozone standard might lead to tighter controls on their NO_x emissions.

The ozone standard affects a large percentage of the population: as of September 2010, 119 million people (nearly 40% of the U.S. population) lived in areas classified "nonattainment" for the current ozone standard. The proposed revision would lower the primary (health-based) standard from 0.075 parts per million—75 parts per billion (ppb)—averaged over 8 hours to somewhere in the range of 70 to 60 ppb averaged over the same time.

EPA has identified at least 515 counties that would violate the proposed ozone NAAQS if the most recent three years of data available at the time of proposal were used to determine attainment (compared to 85 counties that violated the standard in effect at that time). The proposal would also, for the first time, set a separate standard for public welfare, the principal effect of which would be to call attention to the damage by ozone to forests and agricultural productivity.

As with other NAAQS, the standards, when finalized, would set in motion a long implementation process that has far-reaching impacts. The first step, designation of nonattainment areas, is expected to take place within a year of the new standards' promulgation; the areas so designated would then have 3 to 20 years to reach attainment.

EPA is prohibited by the statute from considering costs in setting NAAQS, but it does prepare cost and benefit estimates for information purposes. The agency estimated that the costs of implementing the revised ozone NAAQS (for all sources of ozone precursors) would range from \$19 billion to \$25 billion annually in 2020 if the standard chosen is 70 ppb, or \$52 billion to \$90 billion if the standard chosen is 60 ppb,⁴⁹ with benefits of roughly the same amount.

Although the ozone NAAQS revision is one of the most expensive EPA rules under development, it is unlikely to have major impacts on electric generating units. Fuel combustion by electric utilities accounted for 13% of NO_x emissions nationally in 2009, and less than 1% of VOC and CO emissions. Thus, other sources account for most of the emissions and are likely to be the main focus of the emission controls necessary to reach attainment of the standard. Furthermore, to the extent that utility NO_x emissions are targeted, it will likely be through the Cross-State Rule, or a successor to it, whose impacts were discussed above. The ozone NAAQS would primarily serve as a driver in the development of these other rules.

As with the SO₂ NAAQS, EEI included the ozone NAAQS on its "train wreck" diagram, but neither EEI nor NERC considered the standard in their analyses.

Particulate Matter

A third NAAQS whose revision could affect coal-fired power plants is that for particulate matter (PM). The PM NAAQS, which includes standards for both coarse and fine particulates (PM₁₀ and PM_{2.5}, respectively), was last revised in October 2006. The D.C. Circuit Court of Appeals remanded the PM_{2.5} standards to EPA in February 2009,⁵⁰ so EPA is both conducting the statutory

⁴⁹ U.S. EPA, "Fact Sheet: Supplement to the Regulatory Impact Analysis for Ozone," January 7, 2010, at <http://www.epa.gov/air/ozonepollution/pdfs/fs20100106ria.pdf>.

⁵⁰ *American Farm Bureau Fed'n v. EPA*, 559 F.3d 512 (D.C. Cir. 2009).

five-year review of the standard and responding to the D.C. Circuit decision. The agency expects to propose revised standards for both PM_{2.5} and PM₁₀ by summer 2011, with promulgation perhaps taking place in 2012.

EPA staff have recommended a strengthening of the PM NAAQS,⁵¹ but at this time, there is no proposal to be evaluated. Fuel combustion by electric utilities is the source of 8.3% of PM_{2.5} and 3.5% of PM₁₀.

As with the other NAAQS, EEI included the PM NAAQS on its "train wreck" diagram, but neither EEI nor NERC considered the standard in their analyses.

Revised Cooling Water Intake Rule

Power plants withdraw large volumes of water for production and, especially, to absorb heat from their industrial processes. Water withdrawals by electric generating plants, used primarily for cooling, are the largest water use category by sector in the United States—201 billion gallons per day (BGD) in 2005. Although water withdrawal is a necessity for these facilities, it also presents special problems for aquatic resources. Cooling water intake structures (CWIS) can cause two types of environmental harm. First, impingement occurs when fish, invertebrates, and other aquatic life are trapped on equipment on intake screens at the entrance to the CWIS. Second, entrainment occurs when small organisms pass through the intake screening system, travel through the cooling system pumps and tubes, and then are discharged back into the source water. Impingement and entrainment injure or kill large numbers of aquatic organisms at all life stages. Section 316(b) of the Clean Water Act (CWA) authorizes regulation of CWIS to protect such organisms from being harmed or killed.

Regulatory efforts by EPA to implement Section 316(b) have a complicated history over 35 years, including legal challenges at every step by industry groups and environmental advocates. Currently most new facilities are regulated under rules issued in 2001, while rules for existing facilities issued in 2004 were challenged and remanded to EPA for revisions. In response to the remand, in March 2011 EPA proposed national requirements expected to affect 559 existing electric generators; 483 are fossil-fuel facilities. The affected facilities comprise approximately 11% of the steam electric generating facilities and over 45% of the electric power sector capacity in the United States. Publication of the CWIS proposal in the *Federal Register* on April 20 triggered a 90-day public comment period that ends on August 18, 2011.⁵² EPA is under a court-ordered schedule to issue a final CWIS rule by July 27, 2012.

Even before release, the proposed regulations were highly controversial among stakeholders and some Members of Congress who questioned whether a stringent and costly environmental mandate could jeopardize reliability of U.S. electricity supply. Many in industry feared, while

⁵¹ On July 2, 2010, EPA released the *Second External Review Draft of its Policy Assessment for the Review of the Particulate Matter NAAQS*. The draft represented EPA staff's recommendations to the Administrator. It outlined options for revising both the fine and coarse particulate standard, both of which would make the standards more stringent. The draft is available at http://www.epa.gov/ttn/naaqs/standards/pm/s_pm_2007_pa.html.

⁵² U.S. Environmental Protection Agency, "National Pollutant Discharge Elimination System—Cooling Water Intake Structures at Existing Facilities and Phase 1 Facilities," 76 *Federal Register* 22174-22228, April 20, 2011. On July 20, EPA published a notice providing for 30 additional days of public comment beyond the time originally scheduled, to August 18, 2011. For information, see CRS Report R41786, *Cooling Water Intake Structures: Summary of EPA's Proposed Rule*, by Claudia Copeland.

environmental groups hoped, that EPA would require installation of technology called closed-cycle cooling that most effectively minimizes the environmental damage of CWIS, but also is the most costly technology option.

In its proposed rule, EPA evaluated four regulatory options expected to minimize the harm to aquatic species of CWIS at existing facilities, each with varying environmental benefits and costs.⁵³ The agency concluded that closed-cycle cooling reduces CWIS impacts to a greater extent than other technologies, but declined to mandate closed-cycle cooling universally and instead favored a less costly, more flexible regulatory option. EPA's recommended approach would essentially codify current CWIS permitting procedures for existing facilities, which are based on site-specific determinations and have been in place administratively for some time because of legal challenges to previous rules. The agency based the conclusion to not mandate closed-cycle cooling on four factors: additional energy needed by electricity and manufacturing facilities to operate cooling equipment, and threats to reliability of energy delivery (i.e., energy penalty); additional air pollutants that would be emitted because fossil-fueled facilities would need to burn more fuel as compensation for the energy penalty; land availability concerns in some locations; and limited remaining useful life of some facilities such that retrofit costs would not be justified. EPA estimates that more than 90 of the 559 affected electric generators already have the technology required to demonstrate compliance with the proposed rule.

Compliance with the rule, when promulgated in 2012, will be required as soon as possible. For individual facilities, specific compliance deadlines will be set when the facility next seeks to renew its existing CWA discharge permit; such permits are issued for five-year periods and then must be reissued by the permitting authority (state or EPA). Permitting agencies often allow facilities some time to come into compliance with new requirements. As proposed by EPA, for facilities already in compliance with the rule or needing to install technologies other than cooling towers, the compliance period is assumed to be a five-year period from 2013 to 2017. EPA expects that facilities required to install cooling towers for entrainment mortality control will require a longer period of time. Fossil-fuel electric power generating facilities would achieve compliance from 2018 to 2022.⁵⁴ EPA estimated that the annual costs of the proposed rule will be \$319 million, while benefits will be \$17.6 million annually.⁵⁵ EPA also estimated that a net nine generating units would be retired as a result of the rule.⁵⁶ EPA did not identify potential retirements by fuel source.

Industry groups generally view the March 2011 proposal favorably (at least in comparison with what had been anticipated), although they favor still more flexibility, while environmental advocates are critical that the proposal does not mandate stricter technological options to provide

⁵³ Three of the regulatory options considered by EPA would require all existing electric generators covered by the rule to use screens to prevent impingement of fish, but they differ with respect to requiring closed-cycle cooling towers to prevent entrainment. The fourth option would allow permitting authorities to establish impingement and entrainment controls on a case-by-case basis for small and medium EGUs and would require uniform controls for larger facilities. The agency's preferred option would require uniform impingement standards (i.e., screens) for all power plants and case-by-case determination of need for cooling towers for all facilities.

⁵⁴ EPA believes that permitting authorities would need to coordinate outages by multiple power generating facilities in a geographic area so as to minimize impacts on reliability of power generation. In these circumstances, EPA expects a facility could reasonably require as long as eight years to attain compliance.

⁵⁵ Costs and benefits are annualized over 50 years and discounted at a 3% rate.

⁵⁶ EPA concluded that 39 EGUs would be retired, but that 30 others would avoid closure because of EPA's recommendation of a rule that does not mandate cooling tower retrofits.

greater protection of aquatic resources. States will be responsible for most permitting actions to implement the rule. Since many states are coping with constrained budgets, some of them favor a regulatory approach that requires them to make fewer case-by-case decisions, thus imposing less administrative cost.

Prior to release of the EPA proposal, industry assumed that the agency would propose a more stringent rule with a more rapid timeline for compliance. Both EEI and NERC assumed that EPA would mandate that existing power plants retrofit by installing closed-cycle cooling systems. EEI assumed that the CWIS rule would affect 314 GW of capacity and a total of 400 electric generating units, at a cost of \$16 billion through 2020. EEI did not estimate or separate out how many plant retirements would result from the anticipated CWIS rule.

The NERC analysis assumed that mandatory cooling tower retrofits would be required by 2018, and on that basis, NERC concluded that the CWIS rule would be the most costly of the four EPA rules that it examined (although NERC did not estimate compliance costs for this rule), with the greatest likely impact on electricity capacity. NERC concluded that such a rule would lead to power plant retirements totaling 33 GW of capacity. However, NERC also concluded that only 2.5 GW of that total would be coal-fired power plants (representing 94 coal steam units). According to NERC, the largest impact of such a CWIS rule would be on older oil- and gas-fired units, with 253 units totaling 30 GW of capacity expected to be economically vulnerable and thus likely to be retired.⁵⁷

Revised Steam Electric Effluent Guidelines

Under authority of CWA Section 304, EPA establishes national technology-based regulations, called effluent limitation guidelines (ELGs), to reduce pollutant discharges from industries directly to waters of the United States and indirectly to municipal wastewater treatment plants. EPA has issued ELGs for 56 industries that include many types of dischargers, such as manufacturing and service industries. These requirements are incorporated into discharge permits issued by EPA and states. The current steam electric power plant rules,⁵⁸ which were promulgated in 1982, apply to about 1,200 nuclear- and fossil-fueled steam electric power plants nationwide, 500 of which are coal-fired.

In a 2009 study,⁵⁹ EPA found that the current regulations do not adequately address the pollutants being discharged and have not kept pace with changes that have occurred in the electric power industry over the last three decades, specifically the increase of flue gas desulfurization (FGD) systems, or scrubbers, at coal-fired power plants to control air pollution. According to EPA, as of June 2008, 30% of coal-fired power plants were using FGD systems to control SO₂ emissions from the flue gas generated in the plants' boilers and prevent buildup of certain corrosive constituents such as chlorides, and by 2025, nearly 80% of coal-fired generating capacity is expected to employ FGD systems. While scrubbers dramatically reduce emissions of harmful pollutants into the air, some create a significant liquid waste stream (especially wet scrubbers). In addition, discharges from coal combustion waste (CCW) ash impoundments at steam electric

⁵⁷ NERC report, pp. 14-15.

⁵⁸ 40 CFR § 423.10.

⁵⁹ U.S. Environmental Protection Agency, *Steam Electric Power Generating Point Source Category: Final Detailed Study Report*, EPA 821-R-09-008, October 2009.

power plants have a potential to degrade water quality. Concern about releases of CCW grew following the collapse of ash impoundment dams at Tennessee Valley Authority (TVA) power plants, discussed further under "Coal Combustion Wastes," below. Pollutants of concern associated with FGD systems and CCW include a large number of metals (e.g., mercury, arsenic, chromium, and selenium), chloride, nitrogen compounds, and total dissolved and suspended solids. EPA believes that many current CWA permits for power plants do not fully address potential water quality impacts of these discharges through appropriate pollutant limits and monitoring and reporting requirements.

Under the CWA, EPA has a duty to review existing ELGs at least every five years and, if appropriate, revise them. EPA had been studying the effluent limitations for the steam electric power generating category since the mid-1990s and on several occasions indicated that a preliminary study of discharges from this category was necessary. In 2009, environmental groups sued EPA to compel the agency to commit to a schedule for issuing revised guidelines. Pursuant to a November 8, 2010 consent decree that it entered into with environmental litigants, EPA agreed to propose the revised power plant ELG by July 23, 2012, and to finalize the rule by January 31, 2014. The rulemaking will address wastewater discharges from CCW ash storage ponds and FGD air pollution controls, as well as other power plant waste streams.⁶⁰ As with the CWIS rule discussed above, compliance with specific regulations, which cannot be anticipated at this time, will occur over several years with full compliance likely not required before 2019 or 2020.

Until EPA proposes a regulation, the substance, cost, and impact of a rule are speculative. Still, even before EPA proposes a new ELG for power plants, the agency has launched an effort to scrutinize state-issued CWA discharge permits for power plants as an interim measure to address longstanding concerns that the permits need to be strengthened. In a June 2010 letter to environmental groups, EPA committed to reviewing at least 35 CWA permits for power plants before the end of 2012 and simultaneously provided EPA regional offices with interim guidance to assist state and EPA permitting authorities to establish appropriate requirements for power plant wastewater discharges.⁶¹

Since EPA has not proposed a revised steam electric power ELG rule, the agency has not provided a Regulatory Impact Analysis or cost estimate for such a rule. EEI included an ELG rule in the timeline shown in **Figure 1**, but did not analyze or project what a rule would look like, or what its impact might be. NERC did not include an ELG rule in its analysis.

Coal Combustion Waste⁶²

Coal combustion waste (CCW) is inorganic material that remains after pulverized coal is burned for electricity production.⁶³ A tremendous amount of the material is generated each year—

⁶⁰ Separately, EPA also is considering regulation of coal ash disposal sites under Resource Conservation and Recovery Act, as discussed in this report under "Coal Combustion Waste."

⁶¹ James A. Hanlon, Director, EPA Office of Wastewater Management, "National Pollutant Discharge Elimination System (NPDES) Permitting of Wastewater Discharges from Flue Gas Desulfurization (FGD) and Coal Combustion Residuals (CCR) Impoundments at Steam Electric Power Plants," memorandum, June 7, 2010, on file with authors.

⁶² This section of the report was written by Linda Luther, Analyst in Environmental Policy.

⁶³ In its June 2010 regulatory proposal, EPA refers to the material as coal combustion *residuals*. It is also commonly referred to as coal combustion *byproducts* or *materials*. How the material is referred to generally depends on the (continued...)

industry estimates that as much as 135 million tons were generated in 2009, making it one of the largest waste streams generated in the United States. Disposal of CCW onsite at individual power plants may involve decades-long accumulation of tons of dry ash (in a landfill) or wet ash slurry (in a surface impoundment) deposited at the site.

On December 22, 2008, national attention was turned to risks associated with managing such large volumes of waste when a breach in a surface impoundment pond at TVA's Kingston, TN, plant released 1.1 billion gallons of coal fly ash slurry that damaged or destroyed homes and property. Beyond the potential for a sudden, catastrophic release from a surface impoundment, a more common threat associated with CCW management is the leaching of contaminants likely present in the waste, primarily heavy metals, resulting in surface or groundwater contamination. This risk is particularly high at unlined surface impoundments which are likely in common use today.

The Kingston release also brought attention to how the waste is managed and regulated. CCW management is largely exempt from federal regulations and is regulated by individual states. State requirements generally apply to two broad categories of CCW management—its *disposal* in landfills, surface impoundment, or mines, and its *beneficial use* (e.g., as a component in concrete, cement, or gypsum wallboard, or as structural or embankment fill). Inconsistencies and deficiencies in state regulatory programs have been identified by EPA as one reason that national standards to regulate CCW are needed. More recently, EPA called into question the effectiveness of some state regulatory programs for protecting human health and the environment.

As discussed below, to establish a national standard necessary to address potential threats of improper management of CCW to human health and the environment, on June 21, 2010, EPA proposed two regulatory options.⁶⁴

Regulatory Background

The evolution of CCW regulation began in 1978 when EPA first proposed hazardous waste management regulations under Subtitle C of the Resource Conservation and Recovery Act (RCRA).⁶⁵ However, in 1980, Congress amended the law to exclude CCW from regulation under Subtitle C, pending EPA's completion of a report to Congress and regulatory determination on whether hazardous waste regulations were warranted.⁶⁶ In response, EPA published regulatory determinations in 1993 and 2000 retaining that exemption, concluding on both occasions that CCW did not warrant regulation as hazardous waste. However, in the 2000 determination EPA stated that national regulations under Subtitle D (applicable to non-hazardous solid waste) were

(...continued)

context in which it is being discussed. For example, coal combustion *waste* is generally destined for disposal, while coal combustion *byproducts* or *residuals* may be destined for some use such as a component in gypsum wallboard or cement. Regardless of what it is called, these terms refer to the same substances. Since EPA's regulatory proposal primarily discusses issues associated with the materials' disposal, it is referred to here as coal combustion *waste* (CCW).

⁶⁴ U.S. EPA, "Hazardous and Solid Waste Management System; Identification and Listing of Special Wastes; Disposal of Coal Combustion Residuals From Electric Utilities," 75 *Federal Register* 35127-35264, June 21, 2010.

⁶⁵ RCRA actually amends earlier legislation, the Solid Waste Disposal Act of 1965, but the amendments were so comprehensive that the act is commonly referred to as RCRA rather than by its official title.

⁶⁶ This exclusion was specified in Solid Waste Disposal Act Amendments of 1980 (P.L. 96-482) at 42 U.S.C. 6921(b)(3)(A)(i). The provisions are commonly referred to as the "Bevill Amendment" or the "Bevill exclusion."

warranted for CCW disposal in landfills and surface impoundments for reasons including new data about potential risks to human health and the environment and concerns about the adequacy of state regulatory programs. EPA stated that it would revise its determination that regulation under Subtitle C was not needed if it found that a need for such regulation was warranted.

After accumulating new data regarding CCW management, in October 2009, EPA developed a draft regulatory proposal to list the material as hazardous waste under Subtitle C of RCRA. Under the draft proposal, EPA would establish land disposal and treatment standards for CCW. EPA cited several reasons for determining that regulation under Subtitle C was needed based on new data which showed that disposal in unlined landfills and surface impoundments presents substantial risks to human health and the environment from releases of toxic constituents, that a large amount of waste is still being disposed in units that lack necessary protections, and state programs have not been sufficiently improved to address gaps that EPA had previously identified.⁶⁷

Current Regulatory Proposal

As a result of review by the Office of Management and Budget, EPA's draft proposal underwent substantial changes. The final proposal, published on June 21, 2010, stated that the determination to revise the regulatory determination had not yet been made. It proposed two regulatory options for consideration. Under the first option, EPA would draw on its existing authority to list a waste as hazardous and to regulate it. The second option would keep the Subtitle C exclusion in place, but would establish national criteria applicable to landfills and surface impoundments under RCRA's Subtitle D non-hazardous solid waste requirements. Under Subtitle D, EPA does not have the authority to implement or enforce its proposed requirements. Instead, EPA would rely on states or citizen suits to enforce the new standards. However, in support of the Subtitle D option, EPA cited industry's concern that labeling CCW as hazardous waste would stigmatize beneficial uses of the material and ultimately increase the amount that must be disposed.⁶⁸

The public comment period for EPA's proposal ended on November 19, 2010. It is unclear when, or if, EPA will ultimately promulgate a final rule. On March 3, 2011, EPA Administrator Lisa Jackson testified that she does not anticipate a final rule to be promulgated in 2011, due to the large number of public comments received.⁶⁹

During several congressional hearings, some Members of Congress also have expressed concern over EPA's ultimate decision to regulate CCW. Their concerns about potential Subtitle C regulations relate primarily to the potential impacts those requirements may ultimately have on coal-producing states, state regulatory agencies, energy prices, and CCW recycling opportunities. On the other hand, concerns expressed by other Members regarding the Subtitle D option generally relate to concerns that human health and the environment would not be sufficiently protected given EPA's lack of authority to enforce Subtitle D requirements.

⁶⁷ For more information about EPA's regulatory proposal, see CRS Report R41341, *EPA's Proposal to Regulate Coal Combustion Waste Disposal: Issues for Congress*, by Linda Luther.

⁶⁸ Opponents of the Subtitle D option have argued the opposite point—that recycling may actually increase if disposal becomes more costly under the Subtitle C requirements.

⁶⁹ House Committee on Appropriations, Subcommittee on Interior, Environment, and Related Agencies, March 3, 2011, EPA budget hearing.

EPA's Regulatory Impact Analysis (RIA) estimated potential costs and benefits associated with the 2010 regulatory proposal. The RIA estimated average annualized regulatory costs to be approximately \$1.5 billion a year under the Subtitle C option and \$587 million a year under the Subtitle D option. EPA also estimated annualized "regulatory benefits." Under the Subtitle C option, regulatory benefits would range widely depending on whether there would be increases in recycling due to added costs of disposal, or decreases in recycling due to possible "stigma" effects of regulating the material under Subtitle C.⁷⁰ EPA estimated that if a decrease in beneficial use were to occur, this could result in increased costs of \$16.7 billion, while induced increases in recycling could result in a regulatory benefit of \$7.4 billion a year. Under the Subtitle D option, the regulatory benefit is estimated to range from \$85 million to \$3 billion a year.⁷¹

The EEI report estimated that if the Subtitle C option were adopted, costs would be considerably higher than projected by EPA, based largely on two costs that were not considered by EPA—costs of retrofitting existing disposal units to meet new standards, and the costs of sending the waste to an offsite commercial hazardous waste disposal facility. With regard to the first cost, neither of EPA's regulatory options would require existing landfills to be retrofitted to meet new regulatory standards as long as they install groundwater monitoring systems and implement corrective action, as needed, while existing surface impoundments would be required to be retrofitted. However, based on its past experience with surface impoundment regulations, EPA assumed that facilities would choose to close rather than retrofit. EEI assumed that some portion would retrofit. With regard to the second cost, EEI assumes that under potential Subtitle C requirements, siting or zoning restrictions and state or local ordinances would affect a facility's decision to open a new CCW landfill. However, these factors are difficult to evaluate. Electric utilities currently operate CCW landfills on-site; no data have been presented that indicate that future landfills could not meet EPA's proposed location restrictions or design requirements or that additional restrictions would prohibit or limit the potential for on-site disposal. Further, according to industry statements, new CCW landfills are already built with liners and groundwater monitoring systems. Thus, there is little evidence to suggest that new Subtitle C standards would differ greatly from what has, up until now, been common industry practice.

Other Regulatory Actions Affecting Coal Power

EPA and other federal agencies (the Office of Surface Mining and Reclamation, in the Department of the Interior; and the U.S. Army Corps of Engineers) are developing a series of actions and regulatory proposals to reduce the harmful environmental and health impacts of surface coal mining, including a practice called mountaintop removal mining, in Appalachia. These actions would not affect electric power plants directly, and thus are not covered by EEI nor NERC in their studies. Nevertheless, numerous critics have included actions by EPA, the Corps of Engineers, and the Interior Department regarding mountaintop removal mining in Appalachia in what they term a "War on Coal." Some of these EPA-Corps-Interior actions are discussed in **Appendix A** to this report.

⁷⁰ Potential benefits to the Subtitle C option also included groundwater protection benefits (e.g., human cancer prevention benefits) and remediation or cleanup costs avoidance after groundwater contamination or surface impoundment breach.

⁷¹ For more detail on cost estimates, see 75 *Federal Register* 35134 and 35211-35220, June 21, 2010.

The Future for Coal-Fired Power

Virtually all the analyses agree that coal will continue to play a substantial role in powering electric generation for decades to come. EPA, for example, in the Utility MACT RIA, concluded that coal-fired generation will be roughly the same in 2015 as it was in 2008, despite the impact of the MACT and other rules.⁷² By 2030, the agency projects that 43% of the nation's electricity will still be powered by coal.⁷³ (The current level is 45%.) EEI projected that coal will be responsible for 36% to 46% of electricity generation in 2020, depending on the scenario.

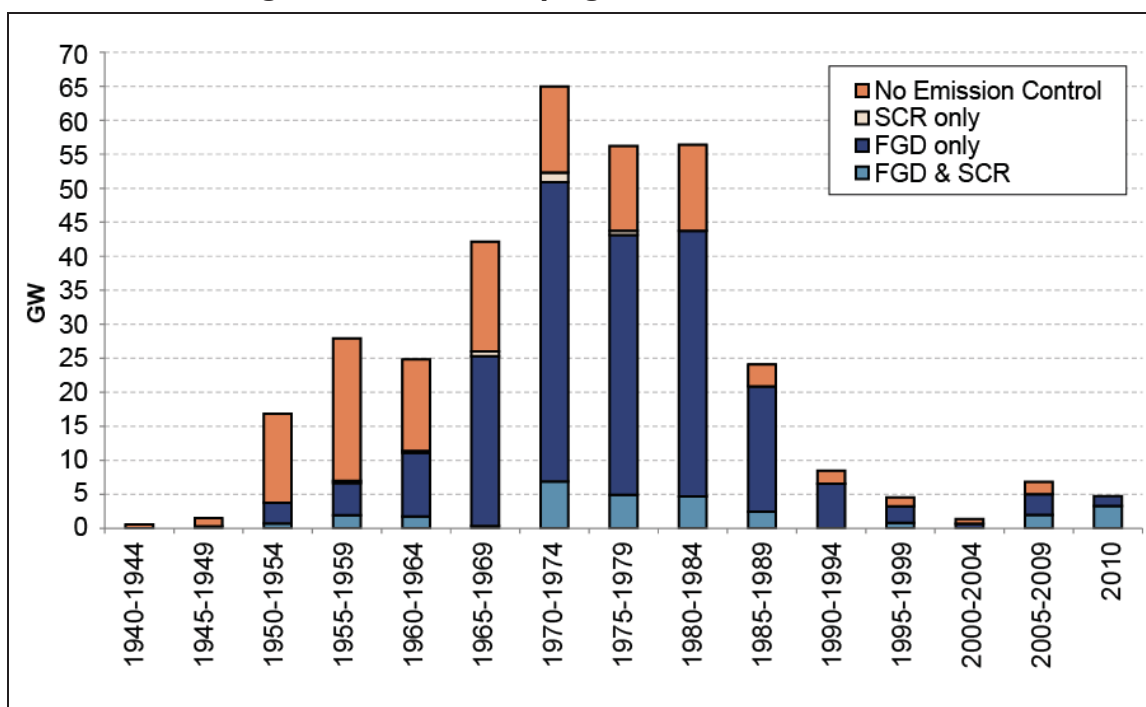
There *will* be retirements of coal-fired capacity, however, as all of the analyses conclude. The number of these retirements, and the role of EPA regulations in causing them, are matters of dispute. The most extreme scenario in EEI's analysis showed 76 GW of coal-fired capacity retirements by 2020 (a little less than 25% of current capacity) as a result of the regulations it analyzed. As noted in the discussion of the individual regulations, in many cases EEI's analysis assumed regulations far more stringent than EPA actually proposed.

The units that would retire are the least economic and/or those currently operating with minimal pollution controls. As noted in **Figure 5**, there are 110 GW of coal-fired plants (about one-third of all coal-fired capacity) that began operating between 1940 and 1969, and two-thirds of these plants do not have scrubbers. These are the prime candidates for retirement.

⁷² Utility MACT RIA, p. 8-16; 2008 data are from U.S. DOE, Energy Information Administration, *Electric Power Annual 2009*, April 2011, Table 2.1, available at http://www.eia.gov/cneaf/electricity/epa/epa_sum.html.

⁷³ Utility MACT RIA, p. 8-16.

Figure 5. Coal Plants by Age and Emission Controls



Source: Sue Tierney, "EPA Proposed Utility Air Toxics Rule –Managing Compliance in Reliable Ways," Congressional Staff Briefing, May 9, 2011, p. 4.

In many cases, these older plants are not base-load plants, so their significance as a percentage of coal-fired generation is less than one might assume from adding up their nominal capacity. In a presentation to congressional staff, Sue Tierney, a former Assistant Secretary of Energy, presented data showing that the pre-1970 units operating without emission controls are in use only 41% of the time.⁷⁴

EPA's modeling confirmed that the plants likely to be retired are older, smaller, and less frequently used: the agency concludes, for example, that under the MACT rule the average unit to be retired will be 51 years old, with an average capacity of 109 Mw (versus 278 Mw for units that will continue operation), and has operated only 56% of the time.⁷⁵

Some of these units will be replaced by new capacity, of which some will be coal-fired, but most replacements are likely to be natural gas combined cycle units. Even before the advent of the "train-wreck" rules, very few coal-fired plants were being built. As shown in **Figure 6**, since 1990, more than 80% of new capacity has been natural gas-fired. These plants are highly efficient; they are cost-competitive with coal; and they emit no SO₂, no mercury, and no other hazardous air pollutants. Without scrubber sludge to manage, they also do not need to meet effluent guidelines. Natural gas-fired power plants also have an advantage with regard to greenhouse gas (GHG) emissions: for the same amount of electric generation, they emit only half the GHGs of coal-fired units.

⁷⁴ Data obtained from Sue Tierney, "EPA Proposed Utility Air Toxics Rule –Managing Compliance in Reliable Ways," Congressional Staff Briefing, May 9, 2011, p. 4. Hereafter, "Tierney presentation." Additional calculation by CRS.

⁷⁵ Utility MACT RIA, p. 8-17.

In the last two years, gas has enjoyed a price advantage, as well. As one analyst notes:

Since most of America's utilities have the ability to employ natural gas fired power plants in lieu of coal fired power plants when natural gas is priced advantageously, utilities have been ramping up natural gas consumption and reducing their usage of coal. With the price of Central Appalachian (CAPP) coal currently trading at \$73 per ton, up from \$60 per ton for much of last year, a recent study by Credit Suisse (CS) indicates that natural gas prices would need to rise to approximately \$6.30 per mcf [thousand cubic feet] before coal and natural gas trade at parity for electricity generation.⁷⁶

Gas is currently trading at around \$4.50 per mcf, with futures contracts through 2014 generally trading below \$6.00.⁷⁷

Train Wreck?

Is there a train wreck coming for coal-fired power? The answer depends on the individual facility. Older, smaller, less efficient units already face a train wreck. In 2010, 48 of them with a combined capacity of 12 GW were retired, according to one source.⁷⁸ Another source identifies 149 coal-fired units with a combined capacity of 19.7 GW whose retirement has been announced or implemented in the past few years.⁷⁹ In recent weeks, as utilities weigh the cost of retrofitting and operating their older units, more retirements have been announced.⁸⁰

⁷⁶ Bill Powers, "Natural Gas vs. Oil and Coal," *Financial Sense*, February 1, 2011, at <http://www.financialsense.com/contributors/bill-powers/natural-gas-vs-oil-and-coal>.

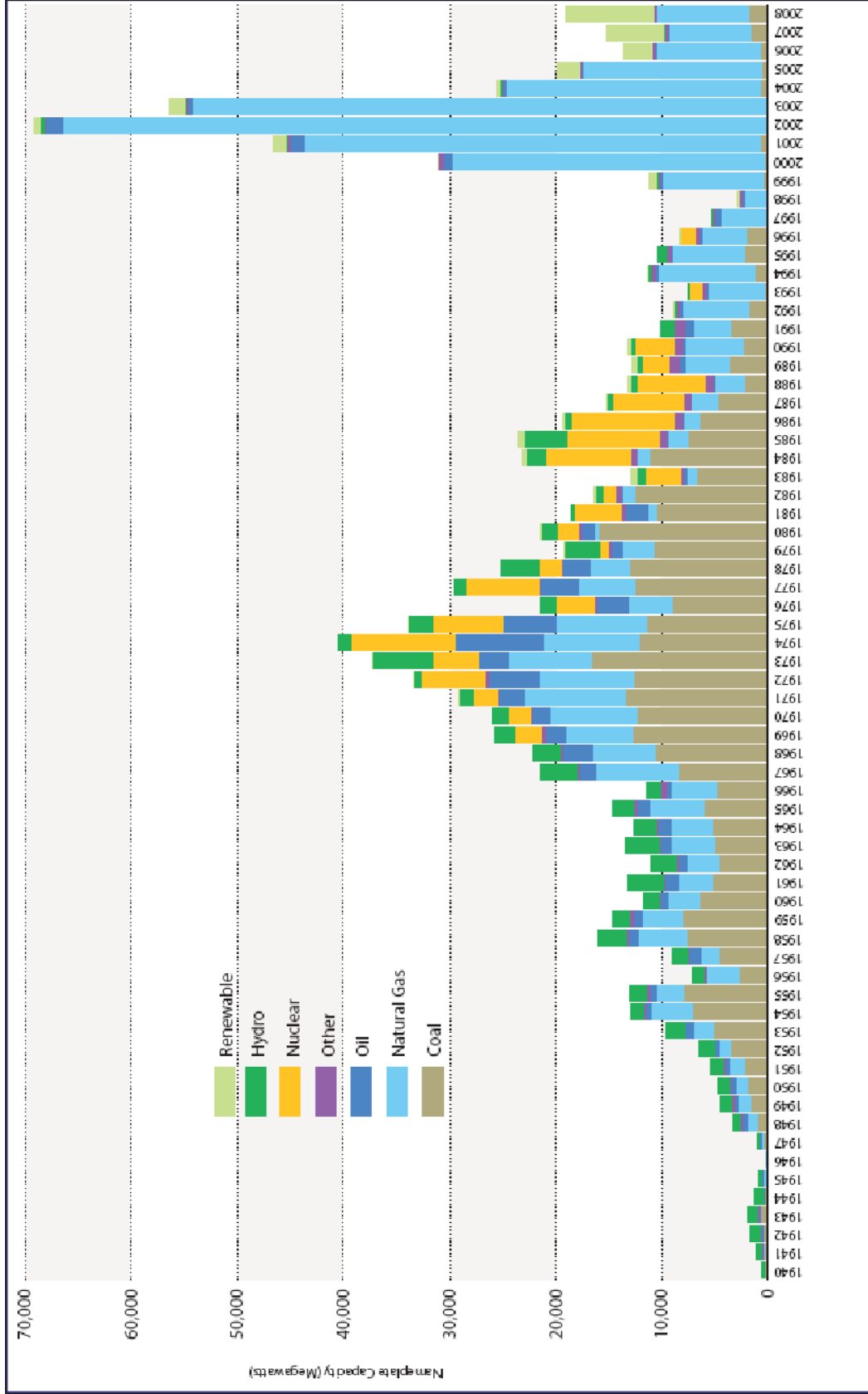
⁷⁷ Commodity Futures Price Quotes for NYMEX Natural Gas, at <http://futures.tradingcharts.com/marketquotes/NG.html>.

⁷⁸ Sierra Club, "2010, Outlook Dimmed for Coal: Year End State of Coal Report," Press Release, December 22, 2010, at http://action.sierraclub.org/site/MessageViewer?em_id=192801.0.

⁷⁹ See Source Watch, "Coal Plant Retirements," at http://www.sourcewatch.org/index.php?title=Coal_plant_retirements#Table_1:_Age_of_U.S._Coal_Plants. Of the 149 units listed, all but 15 were built before 1973.

⁸⁰ American Electric Power announced in early June that it will retire 6 GW of coal-fired capacity, about one-fourth of the capacity of its coal-fired fleet, and will retrofit an additional gigawatt to burn natural gas. TVA, in April, announced that it will retire 18 coal-fired units, replacing them with low emission or zero-emission electricity sources, including renewable energy, natural gas, nuclear power, and energy efficiency.

Figure 6. Power Plant Capacity, by Type and Year It Entered Service



Source: Sue Tierney, "EPA Proposed Utility Air Toxics Rule –Managing Compliance in Reliable Ways," Congressional Staff Briefing, May 9, 2011, p. 10. The chart is based on EIA Form 860 data. A similar chart produced by EIA itself can be found at <http://www.eia.gov/todayinenergy/detail.cfm?id=1830>.

But this does not mean that the newer (post-1970) coal-fired facilities that have invested in pollution controls over the years will be shuttered. Most of them already comply with many of the proposed rules, or if not, they can do so with modest modifications to their pollution control equipment. A train wreck for this group seems unlikely.

In between the two ends of the spectrum are facilities that are efficient enough or play a sufficiently vital role in meeting regional demand that the economics likely would justify their retrofit. For these facilities, the key questions are whether there will be sufficient time to act, and whether the reliability of the electric grid will be affected as they are taken off-line for modification.

Timing and Reliability Issues

It is difficult to generalize about the timing and system reliability issues. Several utilities state that they will have difficulty meeting the deadlines. In congressional testimony, April 15, 2011, Thomas A. Fanning, the Chairman, President, and Chief Executive Officer of The Southern Company, which provides electricity to 4.4 million customers in the Southeastern United States, stated:

The reliability of the nation's electric generating system is at risk because of the number of new rules and regulations applicable to power plants. The stringency of these regulations, the lack of flexibility likely to be provided within these regulations, and, above all, the compliance schedules that will be required put reliability at risk. Accelerated plant retirements and shutdowns triggered by the Utility MACT rule will cause reserve capacity to plummet, increasing the likelihood and severity of service disruptions.⁸¹

In announcing the retirement of one-fourth of its coal-fired generation, June 9, 2011, American Electric Power's Chairman and CEO, Michael G. Morris, in a press release, stated:

We support regulations that achieve long-term environmental benefits while protecting customers, the economy and the reliability of the electric grid, but the cumulative impacts of the EPA's current regulatory path have been vastly underestimated, particularly in Midwest states dependent on coal to fuel their economies. We have worked for months to develop a compliance plan that will mitigate the impact of these rules for our customers and preserve jobs, but because of the unrealistic compliance timelines in the EPA proposals, we will have to prematurely shut down nearly 25 percent of our current coal-fueled generating capacity, cut hundreds of good power plant jobs, and invest billions of dollars in capital to retire, retrofit and replace coal-fueled power plants.⁸²

Others, however, cite historical experience and available indicators to argue that timing and system reliability will not be a problem. Michael Bradley, representing the Clean Energy Group, a coalition of electric power companies with over 200 GW of electric generating capacity, including 105 GW of fossil-fuel fired capacity, testified that:

⁸¹ Testimony of Thomas A. Fanning, "Recent EPA Rulemakings Relating to Boilers, Cement Manufacturing Plants, and Utilities," Hearing, House Energy and Commerce Committee, Subcommittee on Energy and Power, April 15, 2011, p. 13.

⁸² "AEP Shares Plan For Compliance With Proposed EPA Regulations," press release, June 9, 2011, at <http://www.aep.com/environmental/news/?id=1697>.

The Utility Toxics Rule provides the business certainty the electric sector needs to move forward with capital investment decisions;

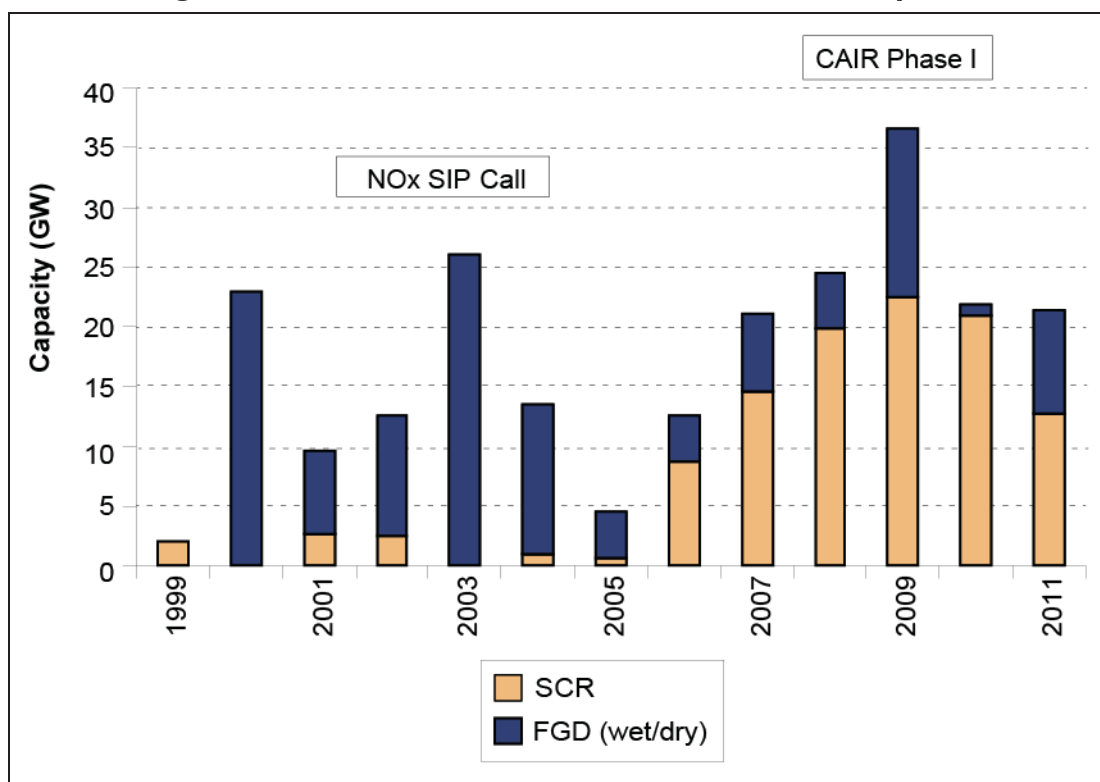
- While not perfect, the proposal is reasonable and consistent with the requirements of the Clean Air Act;
- The electric sector is well positioned to comply; and
- The Clean Air Act provides sufficient time to comply as well as the authority to accommodate special circumstances where additional time is necessary.⁸³

The Institute of Clean Air Companies, which represents the pollution control industry, states that utilities installed 60 GW of scrubbers and 20 GW of selective catalytic reduction (SCR) between 2008 and 2010. (See **Figure 7**.) In the early 2000s, in response to the NO_x SIP Call, the industry installed 96 GW of SCR in a five-year period while successfully maintaining system reliability. This was a “much more capital and manpower intensive effort” than the Utility MACT will be, according to David Foerter, the group’s Executive Director.⁸⁴

⁸³ Testimony of Michael Bradley, “Recent EPA Rulemakings Relating to Boilers, Cement Manufacturing Plants, and Utilities,” Hearing, House Energy and Commerce Committee, Subcommittee on Energy and Power, April 15, 2011, p. 1

⁸⁴ David C. Foerter, Executive Director, Institute of Clean Air Companies, “EPA’s Proposed Utility Air Toxics Rule,” Presentation to Congressional Staff, May 9, 2011, p. 6.

Figure 7. Cumulative SCR and Scrubber Installations, by Year



Source: David C. Foerter, Executive Director, Institute of Clean Air Companies, "EPA's Proposed Utility Air Toxics Rule," Presentation to Congressional Staff, May 9, 2011.

Notes: SCR = Selective Catalytic Reduction technology to reduce NOx emissions. FGD = Flue Gas Desulfurization, commonly referred to as a scrubber.

If necessary, as shown in **Figure 6**, the industry is capable of adding new generating capacity in a short time. From 2000-2003, electric companies added over 200 GW of new capacity, far more than any of the analyses suggest will be needed in the 2011-2017 timeframe.

A December 2010 analysis by FBR Capital Markets concluded that even the incremental retirement of 45 GW by 2014 (which appears to be more than EPA's rules will effect) would have little effect on electricity reserve margins.⁸⁵ "Summer reserve margins are currently 26% across the U.S. and are likely to decline only to 24% by 2014 in a draconian scenario in which 45 GW of generation is retired."⁸⁶ FBR offers the caveat that electricity reserve margins are a regional, not a national matter; but its analysis of eight NERC regions found reserve margins of 16.8% to 37.8% under its "draconian" 2014 scenario.⁸⁷

Other studies suggest that proper planning can prevent a train wreck, even in worst-case scenarios. Much depends on whether individual utilities have already begun planning for the

⁸⁵ Only three of EEI's nine scenarios resulted in that many retirements, and all three assumed regulations far more stringent than EPA has proposed.

⁸⁶ FBR Capital Markets, *Coal Retirements in Perspective – Quantifying the EPA Rules*, December 13, 2010, p. 18.

⁸⁷ *Ibid.*, p. 19. NERC considers 15% to be the necessary planning reserve margin. See NERC, "Reliability Indicators: Planning Reserve Margin," at <http://www.nerc.com/page.php?cid=4%7C331%7C373>.

implementation of the rules, including lining up engineers to design modifications, and conducting preliminary discussions with permitting authorities and grid operators regarding the required steps. This point is stressed by analysts on all sides of the issue. For example, Sue Tierney, after reviewing several studies, states:

The studies' results do not mean that there will be resources gaps; they make it clear that action needs to be taken soon

- These studies serve as a "call to action" ...
- Several are explicit in saying that they have identified resource gaps in order to signal that action is needed.⁸⁸

NERC's study is one of those to which Tierney refers. NERC concluded that, "Regulators, system operators, and industry participants should employ available tools to ensure Planning Reserve Margins while forthcoming EPA regulations are implemented."⁸⁹ Perhaps more importantly, it stated: "NERC should further assess the implications of the EPA regulations as greater certainty or finalization emerges around industry obligations, technologies, timelines, and targets."⁹⁰ Given that the NERC study assumed far more stringent requirements than EPA proposed for both the Cooling Water Intake and Utility MACT rules, a NERC reassessment could be informative.

On August 1, 2011, in response to a letter from Senator Lisa Murkowski, the Federal Energy Regulatory Commission (FERC) weighed in on the debate over reliability. FERC stated that its "... preliminary assessment showed 40 GW of coal-fired generating capacity 'likely' to retire, with another 41"GW 'very likely' to retire"⁹¹ FERC did not reach conclusions as to whether such retirements would cause reliability problems, and it went to some lengths to stress the limitations of its analysis. Of particular note, despite the August 1 date, FERC's analysis was not based on information available at that time. It assumed that once-through cooling water systems would have to be replaced with closed-loop systems,⁹² for example, which is not what EPA had proposed in March 2011. The analysis also did not take into account EPA's July finalization of the Cross-State Air Pollution Rule, which, in comparison to the earlier (proposed) version of the rule, provided additional flexibility for compliance. The Chairman's letter concluded: "... this informal assessment offered only a preliminary look at how coal-fired generating units could be impacted by EPA rules, and is inadequate to use as a basis for decision-making, given that it used information and assumptions that have changed."⁹³

Price and Availability of Natural Gas

The EEI and NERC reports said that EPA rules would make coal-fired power more expensive so that utilities would retire additional coal-burning units (i.e., beyond those they already plan to retire) and replace them with alternative generation that emits fewer pollutants, leading to a drop

⁸⁸ Tierney presentation, p. 9.

⁸⁹ NERC report, p. VII.

⁹⁰ Ibid.

⁹¹ "FERC Response to Senator Murkowski, Proposed EPA Rule," Attachment to letter of Jon Wellinhoff, FERC Chairman, et al., to Hon. Lisa Murkowski, August 1, 2011, p. 5.

⁹² Ibid., p. 2.

⁹³ Ibid., cover letter, p. 1.

in coal-fired generation and equal or greater increase for natural gas. From one perspective, the train wreck debate appears to be a coal-vs.-natural gas argument. The debate is not entirely that simple, however, because gas-burning power plants will be subject to some of the new rules, too. Some rules may affect coal-fired power plants disproportionately compared with other plants, while other rules, such as the cooling water intake proposal, may affect non-coal-fired power plants to a greater extent.

The primary impacts of many of the rules discussed here will be on coal-fired plants more than 40 years old that have not, until now, installed state-of-the-art pollution controls. Many of these plants are inefficient and are being replaced by more efficient combined cycle natural gas plants.

In EEI's analysis (and perhaps in the others that use the Integrated Planning Model⁹⁴), a key variable is the assumed price of natural gas. The price of gas in EEI's reference case rises somewhat compared to today's price of about \$4.50 per MMBtu, but it remains below \$6.00 per MMBtu every year from now until 2035.⁹⁵ This is inexpensive gas, by the standards of recent history, as much as one-third below the price in each of the years 2004-2008. The low prices apparently reflect recent reports that future supplies of gas are projected to be abundant.⁹⁶

In the other scenarios modeled by EEI (i.e., the scenarios showing the impact of EPA's expected regulations), the gas price ranged from about \$5.50 to \$7.50 per MMBtu over the 25 years through 2035. The higher prices presumably are the result of increased demand as some EGUs switch from coal to gas as a compliance strategy. These prices would also be below 2004-2008 prices in most cases.⁹⁷

What the model showed in most of EEI's scenarios, then, is that, because the price of gas was projected to remain low, coal-powered units would be retired or converted to natural gas as EPA imposes the regulatory requirements under consideration.

Two of EEI's scenarios, however, used different assumptions regarding gas prices: they artificially assumed that gas costs either \$1.50 or \$3.00 per MMBtu more than the model's supply curve showed. With more expensive gas, fewer coal-powered facilities would be retired: in the extreme (\$3.00 more) case, 17 GW were retired, compared to 57-71 GW in the same case with lower-priced gas.⁹⁸

What these scenarios tell us is that utilities will look at the impending regulations and decide what to do largely based on their assumptions regarding the cost of the alternatives—natural gas (where it's available) being the most often discussed, but others include conservation, wind, and other renewable resources. If they expect the price of gas to remain low or the cost of other alternatives to be competitive, their primary method of compliance likely will be to retire old coal plants and switch to gas or the alternatives. If they expect the price of gas or other alternatives to be high, they'll invest the money in retrofitting the coal plants to reduce their emissions.

⁹⁴ The Integrated Planning Model, developed by ICF Inc., is used by EPA, EEI, and others to model the impacts of environmental regulations on the electric power industry.

⁹⁵ Natural gas price projections are shown on page 58 of the EEI report.

⁹⁶ The comparison is to EIA data shown in **Figure 4** above.

⁹⁷ All the scenarios, including the Reference case, assume a brief price peak in 2015, with prices declining for the next 15-20 years thereafter.

⁹⁸ EEI report, Table 3.1.

As the NERC report stated:

Unit retirement is assumed when the generic required cost of compliance with the proposed environmental regulation exceeds the cost of replacement power.... For the purpose of this assessment, replacement power costs were based on new natural gas generation capacity. If the unit's retrofit costs are less than the cost of replacement power, then the unit is marked to be upgraded and retrofitted to meet the requirements of the potential environmental regulation, i.e., it is not considered "economically vulnerable" for retirement.⁹⁹

As utilities attempt to forecast the price of natural gas, their conclusions will be based in large part on assumptions as to whether gas will be available in sufficient quantities to meet the increased demands of electric power generation. Natural gas faces its own controversies, as domestic production increasingly relies on "unconventional" sources such as shale, from which gas is obtained by hydraulic fracturing. (For additional information on this practice, see CRS Report R41760, *Hydraulic Fracturing and Safe Drinking Water Act Issues*, by Mary Tiemann and Adam Vann.) Nevertheless, a 2009 NERC report stated:

Concerns regarding the availability and deliverability of natural gas have diminished during 2009 as North American production has begun to trend upward due to a shift toward unconventional gas production from shale, tight sands, and coal-bed methane reservoirs. In its latest biennial assessment, the Potential Gas Committee increased U.S. natural gas resources by nearly 45 percent to 1,836 TCF [trillion cubic feet], largely because of increases in unconventional gas across many geographic areas. Pipeline capacity has similarly increased, by 15 BCFD [billion cubic feet per day] in 2007 and 44 BCFD in 2008, with an increase of 35 BCFD expected in 2009. Storage capacity has also increased substantially.¹⁰⁰

In short, the "train wreck" facing the coal-fired electric generating industry, to the extent that it exists, is being caused by cheap, abundant natural gas as much as by EPA regulations. As John Rowe, Chairman and CEO of Exelon Corporation, recently stated: "These regulations will not kill coal.... In fact, modeling done on the impacts of these rules shows that up to 50% of retirements are due to the current economics of the plant due to natural gas and coal prices."¹⁰¹

Legislation

Congress has shown a great deal of interest in the forthcoming EPA power plant rules and related Administration activities, with both proponents and opponents of EPA action circulating "Dear Colleague" letters and hearings held or scheduled by several House and Senate committees. Legislation to prevent or delay EPA action has passed the House, and more legislation is considered likely. Some recent proposals are broad in nature, targeting EPA generally or a lengthy list of specifics, while others focus more narrowly on individual rules or actions.

⁹⁹ NERC report, p. 6.

¹⁰⁰ NERC, *2009 Long-Term Reliability Assessment: 2009-2018*, October 2009, p. 4, available at http://www.nerc.com/files/2009_LTRA.pdf.

¹⁰¹ John W. Rowe, "Energy Policy: Above All, Do No Harm," Remarks as Prepared, American Enterprise Institute, March 8, 2011, p. 7. Exelon is one of the largest electric and gas utility companies in the United States, serving 13 million people in Illinois and Pennsylvania.

One such broad bill is H.R. 2401, the Transparency in Regulatory Analysis of Impacts on the Nation (TRAIN) Act of 2011. It would establish a panel of representatives of federal agencies to report to Congress by August 2012 on the cumulative economic impact of a number of listed EPA rules, guidelines, and actions concerning clean air and waste management. The House Energy and Commerce Committee approved this bill on July 13. Similar legislation introduced in the Senate, S. 609, the Comprehensive Assessment of Regulations on the Economy Act of 2011, would direct the Department of Commerce to form a panel to review the cumulative energy and economic impacts of specific rules proposed or finalized by EPA or expected soon. Both bills would cover rules discussed in this report. Impetus for this type of legislation is the widely expressed concern that when EPA analyzes impacts of individual regulations, it does not consider costs imposed by multiple rules taking effect more or less simultaneously. Another bill, H.R. 1872 (the Employment Protection Act of 2011) would require EPA to consider the impact on employment levels and economic activity prior to issuing a regulation, policy statement, guidance, or other requirement, implementing any new or substantially altered program, or issuing or denying any clean water or other permit. Companion Senate legislation is S. 1292.

Even before the start of the 112th Congress, House Republican leaders signaled that House committees would scrutinize EPA's rulemaking decisions, including by withholding funding for prospective rules and de-funding previously promulgated rules.¹⁰² This was demonstrated when the House passed H.R. 1, a full-year continuing appropriations resolution for FY2011, in February. As passed by the House, the bill contained more than 20 provisions restricting or prohibiting the use of appropriated funds to implement various regulatory activities under the EPA's jurisdiction—including many discussed in this report.¹⁰³ (On March 9, the Senate failed to approve the House-passed bill and subsequently also did not agree to a substitute text (S.Amdt. 49) that contained different funding levels and generally omitted the EPA regulatory provisions in the House-passed bill.) Final legislation that provided full-year appropriations for EPA (P.L. 112-10) did not include the restrictive provisions in the House-passed bill. Subsequently, many of these same provisions were included as general provisions in legislation providing FY2012 appropriations for EPA (H.R. 2584), which the House considered in July but took no final action on before Congress recessed in early August. As reported by the House Appropriations Committee, H.R. 2584 contains policy provisions that would, for example, prohibit EPA from spending appropriating funds to propose or promulgate rules for greenhouse gas emissions from stationary sources; to modify the PM NAAQS; to finalize or implement the cooling water intake rule; or to propose or implement a coal combustion ash rule. The bill also includes a provision similar to H.R. 2401, described above.

Several bills concerned with specific rules discussed in this report also have been introduced.

The House approved legislation to restrict EPA authority and to repeal a dozen EPA regulatory actions dealing with greenhouse gases (H.R. 910) on April 7. In the Senate, an amendment identical to H.R. 910 (S.Amdt. 183) failed on a vote of 50-50.

As discussed elsewhere in this report (**Appendix A**), EPA's January 2011 veto of a CWA permit for a West Virginia surface coal mining project has been very controversial, including in Congress, and raised questions about adequate coal supplies for power plants. In the 112th

¹⁰² Honorable Jerry Lewis, letter to EPA Administrator Lisa P. Jackson, November 29, 2010, on file with authors.

¹⁰³ For information, see CRS Report R41698, *H.R. 1 Full-Year FY2011 Continuing Resolution: Overview of Environmental Protection Agency (EPA) Provisions*, by Robert Esworthy.

Congress, legislation has been introduced to remove EPA's veto authority from the CWA (H.R. 517), and a number of other bills to modify or clarify this portion of the law also have been introduced (H.R. 457/S. 272, H.R. 468/S. 960, and H.R. 2018). A subcommittee of the House Transportation and Infrastructure Committee held hearings on these issues in May, and on July 13, the House passed H.R. 2018. Several provisions in this bill would limit EPA's authority to provide oversight of states' implementation of the CWA; it would allow the agency to veto a Section 404 permit only with concurrence of the state where the subject discharge originates. As passed, the bill also includes a provisions similar to H.R. 1872, described above; it would require EPA to consider economic impacts before promulgating any clean water rule, or issuing or denying a clean water permit.

Also in the 112th Congress, two bills have been proposed that would prohibit CCW from being regulated under Subtitle C of RCRA—H.R. 1391 (the Recycling Coal Combustion Residuals Accessibility Act of 2011, or the RCCRA Act) and H.R. 1405. On June 21, 2011, a House Energy and Commerce Committee subcommittee approved H.R. 1391.¹⁰⁴

Beyond Congress, some state legislatures also have taken interest in EPA's regulatory activity. In February, the American Legislative Exchange Council issued a report identifying a number of strategies that states could use to oppose EPA's actions: adopting resolutions, conducting enhanced legislative review of state regulations, and enacting bills to assert state sovereignty.¹⁰⁵ Resolutions critical of EPA's actions have been introduced in several state legislatures this year.

Concluding Thoughts About the "Train Wreck" Analyses

EI, NERC, and other recent reports describe scenarios and potential impacts of EPA rules, including projected need for additional power plant capacity or potential reliability problems, that depend on a number of assumptions such as the stringency of the rules or expected tight compliance deadlines, many of which differ greatly from what EPA has actually proposed or promulgated. Also, because most of the reports try to look collectively at EPA rules, to the extent a proposed or promulgated rule differs from some of these assumptions, it can be difficult to separate out one rule's projected impacts from the report's overall conclusions about multiple rules.

Some of the reports project impacts on power plants and electricity supply nationwide, some project impacts on a regional basis. In reality, evaluating regulatory impacts, compliance costs, and possible retirement decisions depends on facility-specific considerations—micro, not macro. Utilities and states will be affected differently. Rules when actually proposed or issued may well differ enough that investment or retirement decisions look entirely different. Technology options available to a unit or plant depend on the specific rule, and compliance costs may be less than

¹⁰⁴ For more information, go to the House Energy and Commerce Committee hearing web page, "Fossil Fuel Combustion Waste Regulation," <http://republicans.energycommerce.house.gov/hearings/hearingdetail.aspx?NewsID=8474>.

¹⁰⁵ American Legislative Exchange Council, "EPA's Regulatory Train Wreck, Strategies for State Legislators," February 2011, <http://www.alec.org/AM/Template.cfm?Section=EPATrainWreck&Template=/CM/ContentDisplay.cfm&ContentID=15364>. According to its website, the American Legislative Exchange Council is an organization of conservative state lawmakers.

projected. Even some units with high assumed control costs, or others that look to be marginal economically, may install controls and continue to operate. Many utilities have already installed technology needed to comply with new rules; for them, costs will be minimal: EPA said that, with regard to the most expensive proposed rule, the Utility MACT, more than half of the coal-fired units fall in this category. The EEI and NERC reports did not account for the fact that plants' compliance costs may be less because of investments already made in pollution control equipment.

Frequently overlooked in analyses of EPA regulations are the benefits to public health and the environment that will occur, benefits that for the most part are difficult to monetize. EPA does estimate benefits of individual rules, while acknowledging that it is challenging to quantify benefits due to data limitations and uncertainties in approaches used to value benefits. The costs of the rules may be large, but, in most cases, the benefits are larger, especially estimated public health benefits. Neither the EEI nor the NERC report addresses benefits.

Although much of the current critical attention to EPA's regulations has focused on rules affecting power plants, especially coal-fired power plants, the rules discussed here are only part of EPA's statutory mandate and regulatory agenda, and there are controversies about many of these other rules, as well, such as a MACT rule to control toxic air pollutants from commercial and industrial boilers and several Clean Water Act rules concerning water quality standards and permits.¹⁰⁶ Further, concerns about impacts of EPA rules have been raised by a range of individual companies and trade associations representing regulated entities beyond the electric utility sector, such as agriculture, chemical manufacturers, water utilities, and others.¹⁰⁷

Several other conclusions bear repeating:

- The studies sponsored by industry groups (EEI and NERC) were written before EPA proposed most of the rules whose impacts they analyze, and they assumed that the rules would impose more stringent requirements than EPA proposed in many cases.
- Of the regulations so far proposed, the Utility MACT, which will set standards for power plant emissions of mercury and other hazardous air pollutants, appears to be the most expensive. EPA's analysis concluded that it will impose annual costs of \$10 billion to \$11 billion annually
- Other rules that industry expected to impose major costs now appear less likely to do so. The Cooling Water Intake rule, for example, proposes a less costly, more flexible regulatory option than EEI and NERC anticipated. Further, NERC believes that few coal-fired EGUs will be affected by this rule, which will have greater impact on older, oil-fired units. The Coal Combustion Waste Rule has been delayed, with no deadline for promulgation.
- For coal-fired plants, the primary impacts will be on units more than 40 years old that have not, until now, installed state-of-the art pollution controls. Many of

¹⁰⁶ For additional information, see CRS Report R41561, *EPA Regulations: Too Much, Too Little, or On Track?*, by James E. McCarthy and Claudia Copeland.

¹⁰⁷ Regarding agriculture's interest in EPA rules, see CRS Report R41622, *Environmental Regulation and Agriculture*, coordinated by Megan Stubbs.

these plants are inefficient, and are being replaced by more efficient combined cycle natural gas plants.

- Lower prices for natural gas and recent increases in its projected availability may reduce the impact of the proposed rules on electric utilities and consumers, although they may lead to more retirements of coal-fired units.
- There is a substantial amount of excess generation capacity at present, due in part to the recession and also due to the large number of natural gas combined cycle plants constructed in the last decade, muting reliability concerns.

Implementation

Finally, several other points regarding the timing of implementation of EPA rules are worth underlining:

- Many proposed and “pre-proposal” rules linger for years without being promulgated; thus, many of the EPA actions described here may not be finalized or take effect for some time. They may also be substantially altered before they become final (i.e., before sources of pollution actually are affected by control requirements), as a result of the proposal and public comment process, and/or judicial review.
- Although EPA generally announces a schedule under which it plans to propose and promulgate rules, experience suggests that proposal and promulgation may take longer than estimated, particularly in cases that do not have court-ordered deadlines.
- Even court-ordered dates for proposal or promulgation may change. It is not uncommon for EPA to request extensions of time, often due to the need to analyze extensive comments.
- Promulgation of standards is not the end of the road. Virtually all major EPA regulatory actions are subjected to court challenge, frequently delaying implementation for years. As noted earlier, many of the regulatory actions described here are the result of courts remanding and/or vacating rules promulgated by previous administrations.
- In many cases, EPA rules must be adopted by states to which the relevant program has been delegated. Moreover, many states require that the legislature review new regulations before the new rules would take effect.
- For many rules, actions by states may be more significant than what EPA does, because the CAA, CWA, and RCRA allow states to adopt more stringent requirements. For example, EPA’s cooling water intake proposal does not mandate installation of costly closed-cycle cooling systems at all existing power plants. At the same time, an EPA rule does not preclude states from imposing such a mandate, as has occurred and is occurring in several locations (e.g., New York, California, Delaware, and New Jersey).
- Standards for stationary sources under the air, water, and solid waste laws are generally implemented through permits, which would be individually issued by state permitting authorities after the standards take effect. When finalized, a permit would generally include a compliance schedule, typically giving the

permittee several years for installation of required control equipment. Existing sources generally will have several years following promulgation and effective dates of standards, therefore, to comply with any standards.

In short, the road to EPA regulation is rarely a straight path. There are numerous possible causes of delay. It would be unusual if the regulatory actions described here were all implemented on the anticipated schedule, and even if they were, existing facilities would often have several years before being required to comply. Unable to account for such factors, which will vary from case to case, timelines that show dates for proposal and promulgation of EPA standards effectively underestimate the complexities of the regulatory process and overstate the near-term impact of many of the regulatory actions.

Appendix A. Regulatory Actions Affecting Mountaintop Removal Mining

EPA and other federal agencies (the Office of Surface Mining and Reclamation, in the Department of the Interior; and the U.S. Army Corps of Engineers) are developing a series of actions and regulatory proposals to reduce the harmful environmental and health impacts of surface coal mining, including a practice called mountaintop removal mining, in Appalachia. These actions would not affect electric power plants directly, and thus were not covered by EEI nor NERC in their studies. Thus, CRS did not include these regulations in the discussion of the "train wreck" issues in the body of this report. Nevertheless, numerous critics of EPA have included EPA, Corps of Engineers, and Interior Department actions in what they term a "War on Coal." The actions, announced in a June 2009 interagency Memorandum of Understanding, are intended to tighten regulation and strengthen environmental reviews of permit requirements under the CWA and the Surface Mining Control and Reclamation Act (SMCRA).

Also in June 2009, EPA and the Army Corps signed a specific agreement detailing criteria that will be used to coordinate and expedite review of pending CWA permit applications for surface coal mining operations in Appalachia. The agencies are conducting detailed reviews of 79 permit applications to evaluate the permits in order to limit environmental impacts of the proposed activities. This review is proceeding slowly. In June 2010, the Army Corps suspended the use of a particular CWA general permit for surface coal mining activities in Appalachia and proposed a rule to prohibit its use entirely; a finalized rule, expected in 2012, would apply more stringent CWA rules to these coal mining operations.¹⁰⁸

In April 2010 EPA released an interim guidance memorandum that seeks to clarify the agency's tightened requirements for surface coal mining in Appalachia. The guidance will be applied as a framework for EPA's approval of all pending and future reviews of permits to dispose of coal mining waste and other types of Appalachian surface coal mining discharges that are authorized by the CWA. Among other items, the interim guidance sets strict numeric limits on conductivity levels in waters affected by mining activities. Conductivity is a measure of the level of salinity in water associated with discharges of selenium and total dissolved solids that are associated with coal mining wastes. Based on recent scientific literature, EPA has concluded that conductivity above certain levels in Appalachian streams presents a reasonable potential to harm stream biota.

Conductivity, and its use in assessing coal mining impacts on water quality, has become a focus of debate. According to EPA, the 2010 interim guidance is not intended to bring a complete halt to surface coal mining in Appalachia, but to force the industry to adopt practices that will minimize harmful impacts. Environmental groups support the guidance document and EPA's use of conductivity to assess water quality impacts, but industry groups have been highly critical, asserting that the science linking conductivity to water quality impairment is uncertain and that acceptable numeric levels are arbitrary. Lawsuits challenging the guidance have been brought by the States of Kentucky and West Virginia, as well as individual coal companies and trade associations. In January 2011, a federal judge who is hearing one of the challenges denied industry's request to block implementation of the guidance, but also denied the government's

¹⁰⁸ U.S. Department of the Army, Corps of Engineers, "Suspension of Nationwide Permit 21," *75 Federal Register* 34711-34714, June 18, 2010.

request to dismiss the case. EPA is working on revised guidance that incorporates public comments, scientific reviews, and experience of implementing the 2010 guidance. Final guidance had been expected by April 1, but its release has been delayed by interagency review.

In addition, in November 2009, the Department of the Interior's Office of Surface Mining (OSM) issued an Advance Notice of Proposed Rulemaking (ANPR) describing options to revise a SMCRA rule, called the stream buffer zone rule, which was promulgated in December 2008.¹⁰⁹ The Obama Administration identified the 2008 rule, which exempts so-called valley fills and other mining waste disposal activities from requirements to protect a 100-foot buffer zone around streams, for revision as part of the series of actions concerning surface coal mining in Appalachia. OSM identified a broad set of regulatory options that it is considering for revisions to the 2008 rule, ranging from formally reinstating the previous rule with small conforming changes, to requiring stricter buffer zone requirements for mountaintop mining operations on steep slopes. OSM officials have been working on developing a new rule, with the goal of releasing a proposal by early 2011, but none has yet emerged. In addition, EPA and OSM have pledged to strengthen oversight of state CWA and SMCRA permitting, regulation, and enforcement.

Finally, EPA has used CWA authority to veto a permit for a surface coal mining operation in West Virginia, after determining that the activity will have an unacceptable adverse effect on wildlife and fishery resources. EPA's veto has been very controversial, in part because it involves the rare action of cancelling a permit previously issued by the Army Corps. Coal industry groups and those representing manufacturing and other sectors have been highly critical, many saying that to revoke an existing permit creates huge uncertainty about whether water quality permits would be rescinded in the future, producing a ripple effect beyond the coal industry. EPA argues that the veto, while highly unusual, is justified because the project involves unacceptable environmental damages.

Viewed broadly, the Administration's combined actions on surface coal mining displease both industry and environmental advocates. The additional scrutiny of permits, more stringent requirements, and EPA's veto of a previously authorized project have angered the coal industry. At the same time, while environmental groups support the veto and related actions, many favor even tougher requirements.¹¹⁰

Critics assert that collectively the Administration's activities and initiatives concerning surface coal mining in Appalachia are needlessly delaying important projects, thus costing jobs and hurting the nation's energy security. While these actions do not directly affect power plants, they have the potential of doing so indirectly, if they effectively limit or restrict coal supplies. None of these actions are discussed in either the EEI or NERC analysis.

¹⁰⁹ U.S. Department of the Interior, Office of Surface Mining Reclamation and Enforcement, "Stream Buffer Zone and Related Rules; Advance notice of proposed rulemaking; notice of intent to prepare a supplemental environmental impact statement (SEIS)," 74 *Federal Register* 62664-62668, November 30, 2009.

¹¹⁰ For additional information, see CRS Report RS21421, *Mountaintop Mining: Background on Current Controversies*, by Claudia Copeland.

Appendix B. Bibliography of Analytic Reports

Growing interest in the impact of EPA regulation on fossil-fuel power plants, especially coal-fired plants, has generated a large number of analytic reports by policy and advocacy groups using varying assumptions and analytic approaches that reach varying conclusions. Many of these reports were issued prior to proposal or promulgation of a rule.

North American Electric Reliability Corporation, *2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations*, October 2010, http://www.nerc.com/files/EPA_Scenario_Final_v2.pdf.

ICF International, *Potential Impacts of Environmental Regulation on the U.S. Generation Fleet*, Final Report, prepared for Edison Electric Institute, January 2011, http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2011IRP/EEIModelingReportFinal-28January2011.pdf.

Metin Celebi, Frank Graves, Gunjan Bethla, et al., The Brattle Group, *Potential Coal Plant Retirements Under Emerging Environmental Regulations*, December 8, 2010, http://www.brattle.com/_documents/uploadlibrary/upload898.pdf.

National Economic Research Associations, *Proposed CATR + MACT*, prepared for American Coalition for Clean Coal Electricity, May 2011, http://www.americaspower.org/NERA_CATR_MACT_29.pdf.

Dan Eggers, Kevin Cole, Yang Y. Song, and LinLin Sun, Credit Suisse, *Impact of EPA Rules on Power Markets*, September 2010, http://epw.senate.gov/public/index.cfm?FuseAction=Files.View&FileStore_id=b42de70d-b814-4410-831d-34b180846a19. Also see Dan Eggers, Credit Suisse, *Implications of EPA Policy*, April 2011, http://www.fbcinc.com/EIA/presentations/Eggers_04.26.11.pdf.

Wood Mackenzie, "Long-term Viability of Many U.S. Coal Plants at Risk," September 10, 2010, <http://www.woodmacresearch.com/cgi-bin/corp/portal/corp/corpPressDetail.jsp?oid=2178098>.

FBR Capital Markets, *Coal Retirements in Perspective—Quantifying the Upcoming EPA Rules*, December 13, 2010, <http://jlcny.org/site/attachments/article/388/coal1.pdf>.

Hugh Wynne, Francois D. Broquin, and Saurabh Singh, Bernstein Research, *Black Days Ahead for Coal: Implications of EPA Air Emissions Regulations for Energy & Power Markets*, July 21, 2010, <http://grist.s3.amazonaws.com/eparegs/Bernstein%20-%20black%20days%20ahead%20for%20coal%20-%2007%2021%2010.pdf>.

There also have been a number of recent analytic rebuttals to these reports:

Michael J. Bradley, Susan F. Tierney, Christopher E. Van Atten, et al., *Ensuring a Clean, Modern Electric Generating Fleet while Maintaining Electric System Reliability*, August 2010, <http://www.mjbradley.com/documents/MJBAandAnalysisGroupReliabilityReportAugust2010.pdf> and *Summer 2011 Update*, June 2011, <http://www.mjbradley.com/documents/MJBA Reliability Report Update June 7 2011.pdf>.

University of Massachusetts Political Economy Research Institute, James Heintz, Heidi Garrett-Peltier, Ben Zipperrer, *New Jobs – Cleaner Air, Employment Effects Under Planned Changes to the EPA's Air Pollution Rules*, February 2011, <http://www.ceres.org/resources/reports/new-jobs-cleaner-air>.

Susan F. Tierney and Charles Cicchetti, *The Results in Context: A Peer Review of EEI's "Potential Impacts of Environmental Regulation on the U.S. Generation Fleet,"* Summary Report, May 2011, <http://www.supportcleanair.com/resources/studies/file/Tierney-and-Cicchetti-EEI-Peer-Review-Summary-May-2011.pdf>.

World Resources Institute, *Response to EEI's Timeline of Environmental Regulations*, November 2010, http://pdf.wri.org/factsheets/factsheet_response_to_eei_timeline.pdf.

Josh Bivens, Economic Policy Institute, *A Lifesaver, Not a Job Killer, EPA's proposed "air toxics rule" is no threat to job growth*, EPI Briefing Paper, June 14, 2011, [http://w3.epi-data.org/temp2011/BriefingPaper312 \(2\).pdf](http://w3.epi-data.org/temp2011/BriefingPaper312%20(2).pdf).

Jennifer Macedonia, Joe Kruger, Lourdes Long, and Meghan McGuinness, Bipartisan Policy Center, *Environmental Regulation and Electric System Reliability*, June 13, 2011, <http://www.bipartisanpolicy.org/sites/default/files/BPC%20Electric%20System%20Reliability.pdf>

Daniel J. Weiss, Valeri Vasquez, and Stewart Boss, "Mercury Falling, Many Power Plants Already Have Equipment to Slash Mercury, Toxic Contamination," June 21, 2011, http://www.americanprogress.org/issues/2011/06/mercury_falling.html.

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