Environmental Regulation and Electric System Reliability

FROM THE STAFF OF THE BIPARTISAN POLICY CENTER

BIPARTISAN POLICY CENTER

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Disclaimer

This report was prepared by the staff of the Bipartisan Policy Center to promote a better understanding of the possible impacts of U.S. Environmental Protection Agency regulation of the electric power sector and to identify a range of strategies for managing associated reliability concerns. The views expressed here do not necessarily reflect those of the BPC Energy Project or our workshop co-sponsors, presenters, and participants.

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Table of Contents

EXECUTIVE SUMMARY

The electric power sector in the United States faces a changing market environment, one that features reduced or flattened demand, low natural gas prices, new environmental regulations, and continued uncertainty about the future regulation of carbon. Among the regulations recently proposed or currently under development by the U.S. Environmental Protection Agency (EPA) are rules to address air pollution transport, air toxics, coal ash, and cooling water intake structures at existing plants.[1] These regulations are expected to result in significant public health and environmental benefits that, when monetized, are well in excess of compliance costs.[2]

[1] These rules are being proposed under the Clean Air Act and other statutory authorities, which require EPA to protect public health, welfare, and the environment from adverse impacts of power plants.

[2] For example, EPA estimates the health and environmental benefits of the proposed Transport Rule range from $120 to $290 billion in 2014, while compliance costs for that year are estimated to be $2.8 billion (estimates are in 2006 dollars). See United States Environmental Protection Agency. Proposed Air Pollution Transport Rule: Reducing Pollution, Protecting Public Health. http://www.epa.gov/airquality/transport/pdfs/TRPresentationfinal_7-26_webversion.pdf.

Key benefits of the suite of EPA regulations include the avoidance of tens of thousands of premature deaths annually, reductions in pollution-related illnesses, and improved visibility and ecosystem health. These new conditions in the power sector are expected to increase the number of coal-fired power plants that will be retired in the next several years; in fact, a number of plant shutdowns have recently been implemented or announced.

Environmental compliance deadlines are likely to have a strong influence on the timing of these retirements, as plant owners will not want to make significant capital investments in some older, marginal units that might otherwise be shut down soon for economic reasons. This has led to concerns that the power sector could face reliability issues as utilities comply with new regulations. Others have argued that power companies and regional, state, and federal authorities have recourse to a range of technology options and planning approaches that can help them avoid reliability impacts from the impending suite of environmental regulations.

To shed light on these complex issues, the Bipartisan Policy Center (BPC), together with the National Association of Regulatory Utility Commissioners (NARUC) and Northeast States for Coordinated Air Use Management (NESCAUM), hosted a series of workshops to assess the possible impacts of regulation and identify a range of strategies for managing associated reliability concerns.[3] The three workshops featured presentations by leading experts on electric power system reliability, electricity market operations, power sector technology, and pollution control policies and regulations (see Appendix A).[4] Building on the presentations and public dialogue at these workshops, our review of a range of existing analyses, and our own analytic work, BPC has developed a number of findings and recommendations. Our main conclusions are summarized below.

IMPACTS ON THE RELIABILITY OF THE ELECTRIC SYSTEM DUE TO EPA REGULATIONS ARE MANAGEABLE.

BPC analysis indicates that scenarios in which electric system reliability is broadly affected are unlikely to occur. Previous national assessments of the combined effects of EPA regulations reach different conclusions, in part because they make quite different assumptions about the stringency and timing of new requirements and about the availability and difficulty of implementing control technologies. In some cases these assumptions deviate from the specifics of EPA's recent proposals in meaningful ways. Moreover, market factors, such as low natural gas prices, are as relevant as EPA regulations in driving coal plant retirements. A number of recent developments are especially relevant from the standpoint of addressing reliability concerns:

- EPA's proposed cooling water regulations are far less stringent than assumed in the vast majority of analyses, many of which considered worst-case scenarios in which cooling towers would be required on all existing units.
- Some commercially available, lower-cost technologies (e.g., dry sorbent injection) for treating hazardous air pollutants were not factored into most previous analyses. Including them significantly reduces retirement projections.
- Most of the units projected to retire are small, older units that are already operating infrequently. Some of these units may be needed to meet peak demand on the hottest and coldest days or to provide volta ge support. In some cases, there may be viable mechanisms, other than one-to-one capacity replacement, available to serve these needs.[5]
- The industry has significant amounts of existing natural gas generating capacity that is currently under-utilized and may be available to take up the slack, depending on the region.
- Some previous assessments do not account for market responses to future retirements, specifically to the potential for adding new capacity to meet reserve margins. Assuming timely permitting, the need for modest new capacity resources could be met with quick-to-build natural gas turbines, as well as demand side resources.[6]

[3] BPC gratefully acknowledges NARUC and NESCAUM as co-conveners of the workshop series. However, the report is solely a product of the staff of the Bipartisan Policy Center and does not necessarily represent the views of NARUC, NESCAUM, or any of the workshop participants.

[4] Information from each of the workshops, including video and presentations, is available at www.bipartisanpolicy.org.

[5] For example, demand response and energy efficiency programs, energy storage, and transmission upgrades.

[6] Although many gas turbines have been built within 3 years in the recent past, some in industry have raised concern that the permitting process for new construction, including greenhouse gas best available control technology (BACT) determinations, might take up to two to three years, added on top of two year construction for a new gas turbine. BPC modeling projects only 200 MW of new gas capacity would be needed, beyond the 1200 MW of new gas turbines expected in the business as usual scenario to be built by 2015.

SUMMARY OF FORTHCOMING EPA REGULATIONS

TRANSPORT RULE – On July 6, 2010, EPA proposed the Transport Rule, a replacement for the Clean Air Interstate Rule (CAIR) which was previously remanded in a 2008 court decision.[7] The newly proposed Transport Rule would require 31 states and the District of Columbia to meet state pollution limits for sulfur dioxide (SO_2) and nitrogen oxides (NO_x) as a means to ensure compliance with National Ambient Air Quality Standards (NAAQS) for ground-level ozone and fine particulate matter (PM).

UTILITY AIR TOXICS RULE – On March 16, 2011, EPA proposed its Utility Air Toxics Rule under a court-ordered deadline to control hazardous air pollutants, including mercury, acid gases and non-mercury metals.[8] As specified by the Clean Air Act, the Utility Air Toxics Rule provides that plants must com ply with emission limitations for hazardous air pollutants within three years, but allows an additional year for plants to come into compliance if such time is necessary to install pollution controls.

COAL COMBUSTION WASTE DISPOSAL REGULATIONS – On June 21, 2010, EPA published a proposed rule to take comment on whether or not coal combustion waste should be regulated as hazardous waste.[9] These wastes, which primarily consist of coal ash, are generated in large quantities by the power sector. According to the proposal, ash could be regulated as "special waste" under the Clean Air Act's hazardous waste provisions (Subtitle C). Alternatively, EPA could deem the coal ash non-hazardous and regulate under Subtitle D, with self-implementing requirements that are not subject to federal enforcement.

CLEAN WATER ACT SECTION 316(B) COOLING WATER INTAKE STRUCTURES – To protect fish and aquatic ecosystems, EPA proposed regulations on March 28, 2011 for cooling water intake structures at electric generating units (EGU) and other industrial facilities that draw large amounts of water out of rivers, lakes, and oceans. This proposed regulation responds to a settlement agreement that was reached after EPA's earlier cooling water proposals were litigated.

GREENHOUSE GAS PERFORMANCE STANDARDS – On December 23, 2010, EPA announced that it will propose greenhouse gas performance standards for power plants by July 2011 and finalize standards by May 2012. This action is being taken under a settlement agreement. At public "listening sessions" to inform this rulemaking process, EPA indicated that its greenhouse gas performance standards would not be designed to induce "game-changing" technology improvements; rather the Agency aims to bring older plants up to modern standards of efficiency.

[7] *State of North Carolina v. Environmental Protection Agency, Et.al.* (D.C. Cir. 2008)

[8] U.S. Environmental Protection Agency. Proposed Utility Air Toxics Rule. National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units. Signed March 16, 2011. Page 59. Available at //www.epa.gov/ttn/atw/utility/pro/proposal.pdf.

[9] For additional information and the proposed rule see: http://www.epa.gov/wastes/nonhaz/industrial/special/fossil/ccr-rule/index.htm.

A NUMBER OF TOOLS FOR ADDRESSING RELIABILITY CONCERNS ARE AVAILABLE TO INDUSTRY AND TO STATE AND FEDERAL REGULATORS.

EPA should take advantage of its existing statutory authorities to structure clear regulations that include sensible timelines and encourage cost-effective compliance strategies. Specifically, EPA should finalize the flexibilities proposed in its Utility Air Toxics Rule (which sets "maximum achievable control technology" standards for hazardous air pollutants) and 316(b) cooling water rule. Where needed and allowed by statute, EPA and state permitting agencies should grant utilities time extensions – with as much advance notice as possible – to install pollution control technologies and to build the new capacity required to achieve compliance.[10]

Regional, state, and utility analyses should continue to examine the potential localized impacts of retirement and retrofit schedules, as well as opportunities to attract non-conventional capacity resources, such as demand resources, distributed generation, and grid-scale energy storage capacity. While most studies have taken a national approach to reliability assessments, more study is warranted to assess localized reliability impacts in the most vulnerable regions, and efforts should be made to refine and improve analytical tools.

If specific issues are identified, federal and state agencies should consider implementing strategies to assure reliability while utilities complete upgrades or bring new generation online. As a backstop, DOE has emergency powers to keep essential generation on-line, and the President has emergency powers to delay requirements in order to protect national security. In addition, EPA may enter into consent decrees – which set forth the steps needed to resolve non-compliance – to enforce the provisions of the Rule. Such consent decrees, however, should aim to eliminate any economic advantage that companies may otherwise have as a result of operating out of compliance. Consent decrees are negotiated once a company is deemed in violation, and stakeholders may not view this legal mechanism as an acceptable option that could be built into company planning. However, consent decrees do offer an additional means of backstop reliability protection.

[10] Some stakeholders endorse efforts to preempt reliability concerns and provide extra time up front in the process, rather than wait for problems and rely on emergency powers and consent decrees.

NEVERTHELESS, THE ELECTRIC POWER SECTOR AND ITS REGULATORS FACE PLANNING CHALLENGES IF THE AIM IS TO AVOID LOCALIZED RELIABILITY PROBLEMS AND MINIMIZE IMPACTS ON ELECTRIC RATES.

A rapidly shifting market and regulatory environment will create planning challenges for the electric power industry. The compliance deadlines of the Utility Air Toxics Rule, in particular, will accelerate and concentrate the decision-making timeframe for plant retirements, retrofits, and new infrastructure into a short period over the next few years. At the same time, many states are weighing new or stronger approaches to incentivize clean energy, energy efficiency, and/or non-conventional capacity resources. This convergence of issues and planning needs offers an opportunity for the industry and its regulators to work together to optimize policies and investment decisions so as to minimize consumer costs, avoid stranded assets, and maximize the benefits achieved by modernizing the nation's electric power infrastructure. At the same time, it will undoubtedly also present challenges, particularly in heavily affected regions where the resources available to support thoughtful planning and regulatory processes–both in terms of people and funding–are already under severe pressure.

Compliance planning can and should begin early and should take into account existing regulations as well as the expected regulations. If plant owners begin planning now and obtain a one year extension from their permitting authority, they will have almost five years from the date of the proposed rule to the date of the extended compliance deadline. Multi-pollutant planning and efforts to integrate non-conventional capacity resources and transmission planning will help to minimize rate impacts for electric consumers. At the same time, federal, regional, and state entities have appropriate roles to play in supporting planning efforts and mitigating anticipated reliability challenges and costs.

Specifically, state public utility commissions (PUCs) and regional transmission organizations or independent system operators (RTO/ISOs) should coordinate closely with power companies to ensure early multi-pollutant compliance planning and to coordinate retrofit outage schedules. To help with the pacing of control retrofits, states should continue to look for incentives and opportunities to encourage retrofit installations that begin well in advance of compliance deadlines.

Federal agencies, including the Department of Energy (DOE), the Federal Energy Regulatory Commission (FERC), and EPA, should provide analytic and technical support and coordinate with state and regional authorities to facilitate a smooth transition.

This convergence of issues and planning needs offers an opportunity for the industry and its regulators to work together to minimize consumer costs, avoid stranded assets, and maximize the benefits achieved by modernizing the nation's electric power infrastructure.

In light of the tight timeframes involved, state legislatures as well as EPA, DOE, and FERC should pursue strategies to help state utility regulators deal with increased workloads, particularly in the years 2012 through 2014, in order to facilitate timely decisions and allow the design and building of pollution controls and infrastructure, as needed.

DUE TO DIFFERENCES AMONG THE STATES, THERE IS NO SINGLE APPROACH TO COMPLIANCE AND RELIABILITY THAT WILL WORK EVERYWHERE. HOWEVER, A NUMBER OF STRATEGIES ARE ALREADY BEING EMPLOYED TO SUPPORT EARLY PLANNING IN DIFFERENT TYPES OF MARKETS.

In regulated states, the integrated resource planning (IRP) process informs state utility regulators who approve rate plans. State policy makers should consider a multi-pollutant approach for rate recovery and planning decisions. States should also advance policies that encourage and place responsibility with utilities for long term decision-making that avoids stranded assets and minimizes consumer costs. In addition, state regulators should recognize the value of long-term natural gas supply contracts to provide price stability and facilitate project financing. Finally, traditionally regulated states should encourage the development of non-conventional capacity resources as one means to help preserve a reliable bulk electricity system and minimize consumer costs.

In restructured states, the transparency of regional or state wholesale markets makes it easier to anticipate planned retirements and outages; in addition, competitive markets create financial incentives for timely investment in new transmission, generation, and non-conventional capacity. In these states, RTOs and ISOs typically facilitate orderly planning for power plant retirements by requiring utilities to provide advance notice if they intend to retire a unit and by conducting reliability impact studies. In light of the large number of pollution control equipment installations expected under upcoming EPA regulations, these regional entities should also play a more active role in coordinating outages, including between neighboring regions that might rely on each other to meet electricity demand during this transition period.

ENSURING A SMOOTH TRANSITION TO A CLEANER ELECTRIC POWER SECTOR WILL REQUIRE NEW INVESTMENTS IN SUPPLY AND DEMAND-SIDE CAPACITY, AS WELL AS TRANSMISSION AND OTHER INFRASTRUCTURE. STATE AND FEDERAL AGENCIES SHOULD LOOK FOR OPPORTUNITIES TO STREAMLINE THE SITING AND PERMITTING OF NEW INFRASTRUCTURE.

A smooth transition to a cleaner and more efficient generation system will require investments in energy efficiency, demand response strategies, and cleaner new generation capacity along with associated transmission and pipeline infrastructure. Fortunately retired capacity will not need to be replaced on a one-to-one basis to meet energy needs, simply because many of the units likely to be retired are not operating at full capacity now and many other existing units are under-utilized.[11] In some instances, of course, the retirement of an existing generator may give rise to new capacity or transmission needs within a relatively brief period of time. And while the industry has generally been able to add capacity on the scale and within the timeframes needed in the past, policy makers at the state and federal levels should explore approaches to facilitate this process by streamlining procedures for siting and permitting new infrastructure.

THERE MAY BE A SHORT WINDOW OF OPPORTUNITY TO ENACT A LEGISLATIVE FIX THAT COULD GUARANTEE THE ENVIRONMENTAL BENEFITS OF THE CLEAN AIR ACT AND PROVIDE A LOWER COST TRANSITION FOR THE POWER SECTOR.

Although BPC believes that the benefits of power sector regulation, including new regulations such as the Utility Air Toxics Rule, far outweigh the cost, we also recognize that associated compliance costs will not be trivial. EPA estimates that compliance costs for the Utility Air Toxics Rule alone will total $10.9 billion annually. For the average electricity consumer, this translates to an increase of $3 to $4 per month.[12] BPC estimates annual costs of $14.5 billion in 2015 and $18.1 billion in 2025 to comply with the suite of EPA air, water, and waste rules.[13]

Some workshop participants suggested that a legislative fix could provide equivalent or greater environmental benefits at a lower cost than regulatory approaches under existing law, particularly for air pollutants. To be successful, multi-pollutant legislation would need to provide certainty on requirements and timing, and encourage rational and timely investment decisions in pollution controls and new capacity. Further, multi-pollutant legislation should ultimately guarantee the environmental benefits available under current authority, while offering a smoother transition. Several market-based, multi-pollutant legislative proposals have been debated in recent years. While recognizing that it would be politically difficult to advance new legislation, the BPC believes that this approach could provide public health and economic benefits and should be explored in the coming months.

[11] According to EPA, for units projected to retire from the Utility Air Toxics rule, the average capacity factor is 56 percent, the average age is 51 years, and the average size is 109 Megawatts.

[12] U.S. Environmental Protection Agency. Power Plant Mercury and Air Toxics Standards: Overview of Proposed Rule and Impacts. http://www.epa.gov/airquality/powerplanttoxics/pdfs/overviewfactsheet.pdf.

[13] See Section III and Appendix B for details on BPC analysis of the impacts of EPA regulations.

SECTION
I

INTRODUCTION

There continues to be debate about the effect of upcoming EPA regulations on power plant retirements and on the relative impact of these regulations compared to other factors, such as low natural gas prices and the continuing uncertainty surrounding carbon dioxide (CO_2) control. This is reflected in the range of conclusions reached by different analyses and in the spectrum of views that exists regarding whether compliance with the new regulations will present a challenge for the industry or not. Analysts disagree about how many existing coal plants are likely to be retired rather than retrofitted with new pollution controls. They also make different assessments about the ability of under-utilized existing generation, new capacity resources, and transmission upgrades to compensate for retired plants.

> This report summarizes the current state of knowledge about challenges facing the electric power sector as it seeks to maintain reliability without jeopardizing important progress on public health and environmental protections.

Further, some analysts predict that the need to retrofit large numbers of power plants with pollution control equipment within a short timeframe could leave some plants unavailable for a period after the deadline until their compliance obligations are met. This is particularly a concern for Air Toxics requirements, which will take effect in 2015.

The result, according to some analysts, could be power shortages in some regions of the country that would create hardships for consumers and damage the economic recovery. However, other analysts contend that reliability concerns are unfounded or at the least overstated because under-utilized natural gas capacity, transmission from neighboring regions, and other resources are sufficient to compensate for the expected coal retirements. According to this view, even if there are legitimate localized reliability concerns, these concerns can be mitigated through a variety of technical, policy, and regulatory approaches.

Several of the EPA regulations that may have the greatest impact on coal plant retirements have not yet been finalized. However, with the issuance of recent EPA proposals for air, water, and waste regulations, including the March 16, 2011 Utility Air Toxics Rule proposal and the March 28, 2011 proposal on cooling water intake structures, the details are becoming clearer. These recent proposals provide some additional clarity on how new environmental regulations will affect power generation planning.

This report summarizes the current state of knowledge about challenges facing the electric power sector as it seeks to maintain reliability without jeopardizing important progress on public health and environmental protections. Section II of this report describes major market factors and regulations affecting the power sector and Section III summarizes and provides insights on key studies that attempt to predict the impact of EPA regulation and other variables. Section IV identifies strategies for mitigating reliability concerns and discusses the roles of regulators and stakeholders in facilitating a smooth power sector transition. The report concludes with a series of findings and recommendations on how best to meet these challenges.

SECTION
II

OVERVIEW OF CHALLENGES FACING THE U.S. ELECTRICITY SECTOR

In the next decade, our nation's electric power system is expected to transition to a more modern fleet of generators. A key element of this anticipated transformation is the retirement of a significant amount of older and increasingly uneconomic coal-fired capacity. The transition itself will be driven by a range of factors, including low natural gas prices, state renewable portfolio standards, and the possibility of some form of future regulation of greenhouse gases. In addition, many coal plants already face economic challenges as they near the end of – and in some cases, exceed – their design life expectancies.

Finally, forthcoming EPA regulations for air quality, cooling water, and coal combustion waste will put additional pressure on plants that don't yet employ state-of-the-art pollution controls. It is difficult to determine the relative impacts of these factors, but a new era of low and stable natural gas prices–the result of a substantial increase in domestic supply–is expected to be an influential driver of electric power sector market conditions and resource choices for the next several decades.

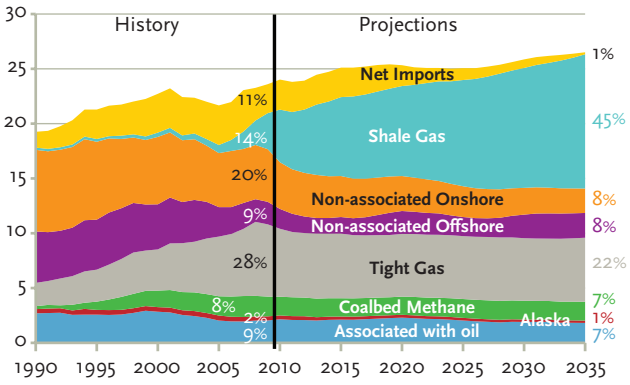
A. THE IMPACT OF NATURAL GAS PRICES

The discovery of vast shale gas basins in the United States, combined with technological advances in horizontal drilling and hydraulic fracturing that make it possible to access these resources, has dramatically changed the domestic natural gas supply outlook (see Figure 1). As new shale gas resources have been developed in recent years, natural gas prices have declined (see Figure 2). They are now projected to remain at levels lower than during the previous decade.[14]

Domestic reserves of natural gas are projected to support more than 100 years of demand at present levels of consumption.[15] Annual U.S. consumption of natural gas across all sectors currently totals approximately 22 trillion cubic feet (Tcf); the electric sector accounts for roughly one-third of this total, or nearly 7 Tcf of annual demand.[16] To give some sense of the current supply context, a recent MIT study titled *The Future of Natural Gas* estimates that approximately 400 Tcf of shale gas in the United States could be developed economically with gas prices at or below $6 per million British thermal units (MMBtu) at the well-head.[17] ICF International, Inc. also recently estimated that almost 1,500 Tcf of total gas can be produced at prices below $5/MMBtu and that the same volume of shale gas alone could be produced at prices below $8/MMBtu.[18]

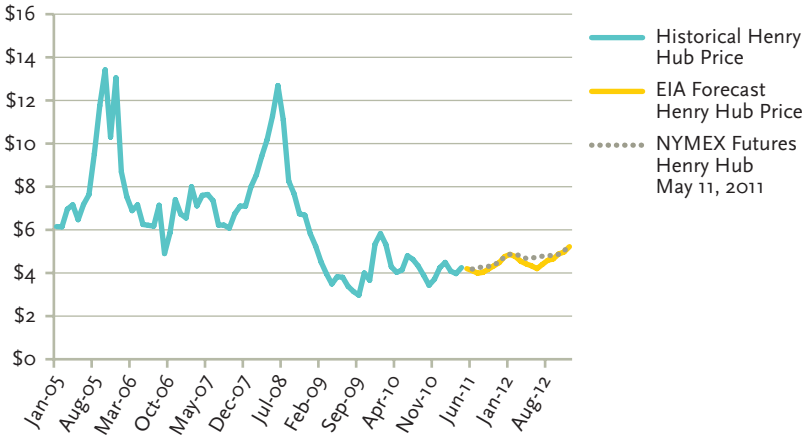
Natural gas plays an interesting role in the power sector's changing supply outlook, as both a driver of coal plant retirements and a solution to potential resource and reliability concerns. Lower gas prices will make some existing coal-fired capacity uneconomic. They may also encourage utilities to increase capacity utilization at existing natural gas-fired plants and, where both types of units are available, dispatch natural gas plants in place of some coal plants. Natural gas has already increased

FIGURE 1: FORECASTED U.S. NATURAL GAS PRODUCTION



Source: U.S. Energy Information Administration. History: Annual Energy Review 2009. Projections: Annual Energy Outlook 2011.

FIGURE 2: PROJECTED NATURAL GAS PRICES



Sources: U.S. Energy Information Administration. Short Term Energy Outlook. May 10, 2011. NYMEX Henry Hub Natural Gas Futures. May 11, 2011.

[14] U.S. Energy Information Administration. Annual Energy Outlook (AEO) 2011. Natural Gas Supply, Disposition, and Prices. The EIA AEO 2011 projects natural gas prices will be nearly $1.24/MMBtu lower, on average through 2030, than their AEO2010 estimate.

[15] Colorado School of Mines. Potential Gas Committee. Potential Supply of Natural Gas in the United States. 2009.

[16] U.S. Energy Information Administration. Natural Gas Consumption by End Use. Data released April 29, 2011.

[17] Massachusetts Institute of Technology. The Future of Natural Gas: An Interdisciplinary MIT Study. Xii.

[18] ICF International. 2010 Natural Gas Market Review, prepared for the Ontario Energy Board. August 2010.

its share of the generation fuel mix during the past few years, displacing some coal generation.[19] In addition, as coal plants retire due to changing economics, low gas prices may provide strategic opportunities to transition to gas-fired capacity at a relatively low cost.

Projections of future low natural gas prices are also changing the market dynamics for investment in renewable and nuclear power technologies, which have relatively higher capital costs. In an environment of low and stable gas prices, these low- and no-carbon sources may have difficulty competing with natural gas absent further incentives or policy interventions (e.g., renewable portfolio standards).

B. CURRENT AND POTENTIAL FUTURE ENERGY POLICIES

State renewable electricity standards have spurred continued growth in clean energy resources, despite low natural gas prices. Such standards, together with federal policies to incentivize clean energy, also impact electric sector investment decisions. As of January 2011, twenty-nine states and the District of Columbia have a Renewable Electricity Standard (RES) or similar policy to promote utility investment in renewable energy, energy efficiency, or other clean resources.[20] Legislation to establish a national renewable electricity standard or clean energy standard has also been introduced at the federal level. Some of these proposals would include nuclear and advanced fossil fuel-based systems with carbon capture and sequestration. The Obama Administration has proposed this latter type of clean energy standard, which would incorporate a broader portfolio of generation resources, including natural gas (as opposed to a portfolio standard that is limited to renewables).

C. FORTHCOMING EPA REGULATIONS FOR THE ELECTRIC POWER SECTOR

EPA has already proposed multiple regulations for the power sector. These regulations will lead to capital investments in new technologies and pollution controls over the next fifteen or so years. The four rules that are expected to have the greatest impact are the Transport Rule, the Utility Air Toxics Rule to ensure compliance with National Emission Standards for Hazardous Air Pollutants (NESHAP), Coal Combustion Waste Disposal Regulations (known as the coal ash rule), and Clean Water Act Section 316(b) regulations for Cooling Water Intake Structures. With the exception of the ash rule, EPA has been directed by the courts to conduct these rulemakings in response to litigation over earlier rulemakings.

CLEAN AIR TRANSPORT RULE

On August 2, 2010, EPA proposed a replacement for the Clean Air Interstate Rule (CAIR), which had been previously remanded in a 2008 court decision. The new Clean Air Transport Rule (CATR), which EPA expects to finalize in the summer of 2011, will require 31 states and Washington, DC to meet new state-level pollution limits for sulfur dioxide (SO_2) and nitrogen oxides (NO_X). Specifically, power plant emissions of SO_2 will have to be reduced by 71 percent from 2005 levels by 2014 and power plant NO_X emissions will have to be reduced by 52 percent from 2005 levels. These reductions are intended to ensure compliance with ozone and fine particulate matter (PM) National Ambient Air Quality Standards (NAAQS). The new Transport Rule limits interstate trading of emission allowances, while the remanded CAIR had allowed unrestricted trading between states. The new Transport Rule also differs from the CAIR proposal in that it precludes previously banked allowances from being used to demonstrate compliance with its new caps.

[19] U.S. Energy Information Administration. Annual Energy Outlook 2011. Electricity Supply, Deposition, Prices, and Emissions.
[20] Database of State Incentives for Renewables & Efficiency. Summary map of RPS policies. www.dsireusa.org. Accessed May 2011.

The previous CAIR proposal, which EPA issued on March 10, 2005, would have permanently capped power sector emissions of SO_2 and NO_X in the eastern United States. The purpose of CAIR was to reduce the interstate transport of pollutants that contribute to non-attainment of fine PM and ozone NAAQS. At the time it was proposed, the health and environmental benefits of this rule were valued at 25 times the estimated cost of compliance.[21]

In July 2008, the US Court of Appeals ruled that CAIR's tradable emission allowance scheme was "fatally flawed" and violated the Clean Air Act (CAA) because it could not ensure that trading would not contribute to another state's non-attainment of the NAAQS. In other words, the Court found that CAIR's trading provisions did not guarantee the ambient air quality improvements needed to achieve the NAAQS in downwind areas. While the court remanded CAIR, it ruled that CAIR would remain in effect until the EPA developed a lawful alternative.[22]

As proposed on August 2, 2010, the Transport Rule would regulate NO_X and SO_2 emissions from electric generating units in the East under a regional cap-and-trade program with limited interstate trading.[23] New NO_X and SO_2 caps would first become binding in 2012 (called "Phase I" in the Transport Rule), and power plants in a limited subset of states would become subject to more stringent "Phase II" caps on SO_2 emissions beginning in 2014.

The compliance options expected to be deployed under the Transport Rule's SO_2 caps include low-sulfur coal, wet and dry scrubbers–known as flue gas desulfurization (FGD) systems–and dry sorbent injection (DSI) with sodium-based sorbents, such as sodium bicarbonate or Trona. Expected options for compliance with the Transport Rule's NO_X caps include low NO_X burners, selective catalytic reduction (SCR), and selective non-catalytic reduction (SNCR). The Transport Rule is intended to address interstate contributions to violations of three specific NAAQS: the 1997 ozone NAAQS and the 1997 and 2006 NAAQS for $PM_{2.5}$. EPA may soon issue updated and more stringent NAAQS for both of these criteria pollutants, and subsequently may issue additional Transport Rules for the control of interstate

> EPA has already proposed multiple regulations for the power sector and has been directed by the courts to conduct these rulemakings in response to litigation over earlier rules.

NO_X and SO_2 emissions after 2014. These successors to the Transport Rule could be implemented within a range of deadlines around 2016-2018, depending on how quickly EPA makes key determinations and how the agency interprets certain timing provisions of the CAA.

UTILITY AIR TOXICS RULE

The 1990 Clean Air Act Amendments include a section (Section 112) on hazardous air pollutants that require EPA to regulate the sources of 90 percent of such emissions by 2000.[24] Because electric generating units were also to be regulated under other sections of the Act in ways that would provide some co-benefits in hazardous air pollutant reductions, Congress required a study and finding to determine if air toxics from electric generating units remained a significant source of concern. In December of 2000, EPA determined that it was "appropriate and necessary" to regulate coal and oil-fired power plants under Section 112.[25]

In 2005, however, EPA reversed course and found that it was neither appropriate nor necessary to regulate power plants under Section 112. At that point EPA removed electric generating units from the list of sources subject to 112.[26] In a March 15, 2005 rulemaking known as the Clean Air Mercury Rule (CAMR), mercury was delisted as a hazardous air pollutant (HAP) and a cap-and-trade policy was enacted under Section 111 of the Clean Air Act with the aim of reducing mercury emissions from coal-fired power plants by 70 percent (i.e., from a national baseline of 48 tons to 15 tons by 2018).[27] On February 8, 2008, the US Court of Appeals for the DC Circuit found that EPA violated the CAA by delisting electric generating units from the Act's toxics provisions and vacated the CAMR.[28,29]

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[21] U.S. EPA. Clean Air Interstate Rule. http://www.epa.gov/cair.

[22] Fozard, Colette. "Interstate Air Pollution Rule Granted Temporary Stay of Execution." Energy Legal Blog. http://www.energylegalblog.com/archives/2009/01/05/1311.

[23] Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone. 75 Fed. Reg. 45,210 (Aug. 2, 2010). (Transport Rule).

[24] Clean Air Act Section 112(n)(1)(A)

[25] 65 FR 79,825

[26] 70 FR 15,994

[27] U.S. EPA. Clean Air Mercury Rule. http://www.epa.gov/camr/basic.html.

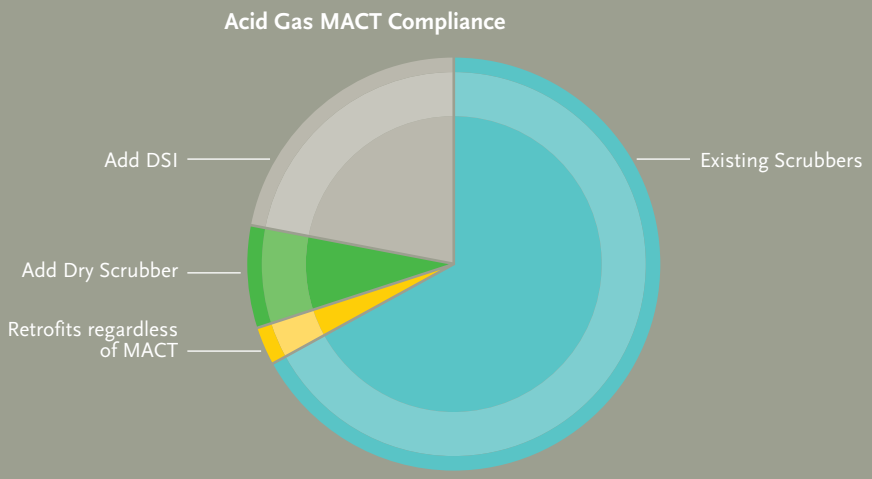
[28] State of New Jersey v. EPA, 517 F.3d 574, 583 (D.C. Cir. 2008), cert. denied, 129 S. Ct. 1308, cert. dismissed, 129 S. Ct. 1313 (2009).

[29] Davis, Tracy. "DC Circuit Orders Immediate Tightening of Mercury Control Rules." Energy Legal Blog. http://www.energylegalblog.com/archives/2008/03/25/1354.

Relevant Air Pollution Control Technologies

- Activated Carbon Injection (ACI): ACI is a commercially available technology that, in combination with particulate controls, removes mercury from the exhaust stack of a power plant. ACI is currently employed at many units to comply with state regulations for mercury control.
- Dry Sorbent Injection (DSI): DSI is a commercially available technology (similar to ACI for mercury) that, in combination with particulate controls, has been shown to significantly reduce emissions of acid gases, as well as sulfur dioxide (SO_2), without a more expensive scrubber. DSI has significantly lower capital cost than a scrubber, but its operating costs are non-trivial due to the cost of sorbent (e.g., Trona). This feature may make DSI best suited for certain fuels (e.g., coals with lower sulfur and chlorine content) and/or for smaller, less frequently operated units. DSI is currently employed on a number of existing power plants and power companies have announced further installation plans. Although there is not a large body of performance data on acid gas removal with DSI, commercial and demonstration projects have shown that this technology can achieve significant reductions in acid gas emissions, at levels on par with Toxics Rule standards.
- Particulate controls: Particle pollution can be captured by particulate controls installed on the exhaust stack of a power plant. Existing power plants generally have some particulate controls, usually electrostatic precipitators (ESP) or fabric filters/baghouses. Depending on the other controls in use and on the type of fuel burned, compliance with the PM limit in the Toxics Rule may require upgrades or the addition of a polishing or full fabric filter.
- Scrubber or Flue Gas Desulfurization (FGD): FGD is a commercially available technology that removes SO_2 as well as acid gases from power plant exhaust. More than half of existing coal-fired generating units currently have a scrubber installed for SO_2 control. Variations include wet scrubbers and dry scrubbers. Wet scrubbers are the most expensive pollution control technology expected to be used for the new air rules.
- Selective Catalytic Reduction (SCR): SCR is a commercially available technology that removes nitrogen oxides (NO_x) from power plant exhaust. It is currently installed at many facilities, particularly in the eastern states. In combination with a wet scrubber, SCR also removes mercury.

FIGURE 3: PROJECTED CONTROL STRATEGIES FOR ACHIEVING ACID GAS LIMITS



Source: U.S. Environmental Protection Agency IPM Data Files for Utility Air Toxics Rule Base and Policy Cases[30]

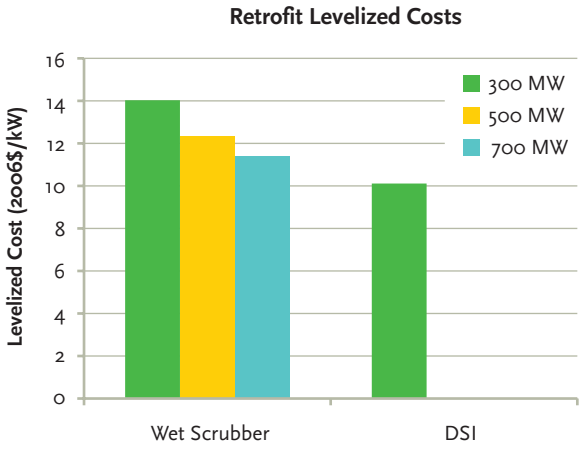
[30] EPA modeling of the Utility MACT rule using IPM runs "ToxR Base Case" and "ToxR Policy Case". Found at http://www.epa.gov/airmarkt/progsregs/epa-ipm/toxics.html. Accessed March 22, 2011.

On March 16, 2011, EPA proposed emission standards for electric generating units under Section 112, consistent with the court ruling. The court ordered a final rule to be issued by November 16, 2011.

The proposed Utility Air Toxics Rule sets emission limitations for three pollutants: mercury, particulate matter, and hydrogen chloride (HCl) based on the average emission rates actually achieved by the top 12% of performers. The standards were designed to assure the achievement of required reductions in the larger category of air toxics. For dioxin/furan, EPA proposed work practice standards based on good combustion practices.

To comply with the Utility Air Toxics Rule, it may be necessary to upgrade or retrofit particulate controls and add activated carbon injection to reduce metallic toxics at many units. In addition, to meet the acid gas HCl limit at uncontrolled plants, it may be necessary to choose between a wet scrubber, dry scrubber, and dry sorbent injection.[31] Specifically, in order to meet the requirements of the Utility Air Toxics Rule, EPA's modeling projects 56 GW of DSI installed in addition to the 9 GW in the base case (for a total of 65 GW) and that 22 GW of Dry FGD will be installed in addition to the 4 GW projected to retrofit in the base case (for a total of nearly 27 GW of dry scrubber installs). EPA projects the Utility Air Toxics Rule will not require installation of any additional Wet FGD beyond 6 GW projected to retrofit in the base case to meet the Transport Rule.[32] If existing pollution controls are included in the count, EPA projects a total of 175 GW of wet scrubbers, 53 GW of dry scrubbers, and 65 GW of DSI will be in place when compliance with the Air Toxics Rule is achieved.[33]

FIGURE 4: COMPARISON OF ANNUAL COSTS OF A WET SCRUBBER VS. DRY SORBENT INJECTION



Source: Technology cost assumptions used in BPC modeling of EPA regulation scenarios, with levelized capital, fixed and operating costs of flue gas desulfurization (wet scrubber), compared with representative cost of dry sorbent injection. Site-specific costs are dependent on various factors including location, fuel-type, and complement of controls. DSI costs are shown for units less than or equal to 300 MW, based on BPC conservative modeling assumption to only offer DSI for such smaller units burning low sulfur coal.

In terms of capital costs, the most expensive control technology for compliance with the Utility Air Toxics Rule is a wet scrubber, as seen in Figure 5 (page 18). Capital costs for an alternative, dry sorbent injection, are significantly lower. On a levelized cost basis, however, the difference is far less significant. Figure 4 shows that the on-going costs for dry sorbent injection, including costs to ship and store large amounts of chemical sorbent, approach the annualized cost of a wet scrubber.

EPA estimates the average annualized cost of compliance with the Utility Air Toxics Rule at $10.9 billion. Estimated net benefits for this rule–taking into account health and other benefits, as well as compliance costs–are estimated to range from $48 billion to $129 billion per year (in 2007 dollars), according to EPA.[34]

COAL COMBUSTION WASTES (ASH) DISPOSAL REGULATIONS

On June 21, 2010, EPA published a proposed rule to take comment on whether or not coal combustion wastes should be treated as hazardous waste.[35] One option would regulate ash as a special waste under subtitle C of the Resource Conservation and Recovery Act (RCRA), which sets guidelines for the management of solid waste. (Currently, coal combustion waste is not covered by subtitle C.) Within the hazardous waste regulations, the coal ash would be classified as a "special waste" to

[31] Some companies suggest that DSI is not a proven option for HCl MACT compliance because there is still limited public data on HCl removal from full-scale DSI applications. On the other hand, a recent study by a national engineering firm endorsed DSI for HCl removal. See Lipinski, G., J. Leonard, C. Richardson. Assessment of Technology Options Available to Achieve Reductions of Hazardous Air Pollutants. URS Corporation. April 2011.

[32] U.S. EPA Base Case pollution control installations include those retrofits projected to occur in the period 2010 through 2013 to comply with the 2012 and 2014 SO_2 and NO_X caps in the Transport Rule.

[33] Data on the number of retrofits and existing controls was calculated from EPA data files from EPA IPM runs to support the Utility Air Toxics Rule. Files: ToxR Base Case and ToxR Policy Case. Found at http://www.epa.gov/airmarkets/progsregs/epa-ipm/toxics.html. Accessed April 1, 2011.

[34] U.S. Environmental Protection Agency. Fact Sheet: Proposed Mercury and Air Toxics Standards. http://www.epa.gov/airquality/powerplanttoxics/pdfs/proposalfactsheet.pdf.

[35] Unofficial proposals were issued May 4, 2010. For additional information and the proposed rule see: http://www.epa.gov/osw/nonhaz/industrial/special/fossil/ccr-rule/index.htm

TABLE 1. KEY DIFFERENCES BETWEEN SUBTITLE C AND SUBTITLE D OPTIONS

	SUBTITLE C	SUBTITLE D
Effective Date	Timing will vary from state to state, as each state must adopt the rule individually-can take 1 - 2 years or more	Six months after final rule is promulgated for most provision: certain provisions have a longer effective date
Enforcement	State and Federal enforcement	Enforcement through citizen suits; States can act as citizens.
Corrective Action	Monitored by authorized States and EPA	Self-implementing
Financial Assurance	Yes	Considering subsequent rule using CERCLA 108 (b) Authority
Permit Issuance	Federal requirement for permit issuance by States	No
Requirements for Storage, Including Containers, Tanks, and Containment Buildings	Yes	No
Surface Impoundments Built Before Rule is Finalized	Remove solids and meet land disposal restrictions; retrofit with a liner within five years of effective date. Would effectively phase out use of existing surface impoundments	Must remove solids and retrofit with a composite liner or cease receiving ash within 5 years of effective date and close the unit
Surface Impoundments Built After Rule is Finalized	Must meet Land Disposal Restrictions and liner requirements. Would effectively phase out use of new surface impoundments.	Must install composite liners. No Land Disposal Restrictions
Landfills Built Before Rule is Finalized	No liner requirements, but require groundwater monitoring	No liner requirements, but require groundwater monitoring
Landfills Built After Rule is Finalized	Liner requirements and groundwater monitoring	Liner requirements and groundwater monitoring
Requirements for Closure and Post-Closure Care	Yes; monitored by States and EPA	Yes; self-implementing

Source: U.S. Environmental Protection Agency

avoid the stigma associated with a hazardous designation and to allow continued beneficial uses of coal ash.[36] This option would regulate ash disposed in landfills and surface impoundments from all electric utilities and independent power producers. Coal ash would be regulated from the point where it is generated to final disposal. This means generators and transporters, as well as facilities that manage, treat, or store coal combustion waste would be subject to regulation.

A second option would instead regulate coal ash under subtitle D of RCRA. Under this proposal, EPA would establish performance standards for landfills and surface impoundments where coal combustion waste is disposed, but it would not regulate its generation, transport, or pre-disposal treatment. Under subtitle D, EPA does not have authority to enforce its requirements.

In practice, regulation under either subtitle C or subtitle D will require many of the same control technologies (see Table 1) including modifications to remove solids, line surface impoundments, and improve wastewater treatment. The main difference is whether or not the requirements are state vs. federally enforceable. While subtitle C would establish federally enforceable "special waste" provisions, the subtitle D option would establish self-implementing requirements for "non-hazardous waste" that are not federally enforceable. In the latter case, enforcement actions could only be triggered by citizen suits (including suits brought by states).

The proposed rule estimates a range of regulatory costs: $3–$20 billion over the life of the program or average annualized costs ranging from $236 million to $1.5 billion. There is some concern that designating coal

[36] Presently, coal combustion waste is used for a number of beneficial uses. Coal ash has a number of agricultural and highway applications and gypsum products are frequently used in wallboard production.

combustion waste as "special waste" may further increase costs if it has the effect of constraining beneficial uses of coal ash, such as in wallboard and concrete. Materials that cannot be put to use will require disposal and, instead of representing a source of revenue, will contribute to additional costs. When factoring in the environmental benefits of the regulation, EPA estimates the average annualized net benefits of its rule will range from approximately $193 million to $18 billion.

CLEAN WATER ACT SECTION 316(B) COOLING WATER INTAKE STRUCTURES

Section 316(b)of the Clean Water Act (CWA) requires EPA to develop regulations on cooling water intake structures at electric generating units (EGU) and other industrial facilities that use large amounts of cooling water for purposes of reducing the mortality of aquatic species due to impingement and entrainment.[37,38] Specifically, the Act requires EPA to demand that cooling intake structures use the "best technology available for minimizing adverse environmental impact."[39] EPA originally promulgated these regulations in three phases: Phase I (covered in a 2001 rulemaking) regulates new facilities (both EGUs and industrial facilities); Phase II (issued in 2004) regulates existing EGUs that use large amounts of cooling water; Phase III (issued in 2006) establishes requirements for other facilities that use cooling water intake structures.[40]

The Phase I regulations require the use of closed-cycle cooling systems on new facilities. The Phase II regulations on existing facilities did not, however, establish a similar requirement. Instead, EPA set performance standards based on mortality rates. These standards could be met through a variety of technologies and would be chosen by cost-benefit analysis.[41]

In Entergy Corp. v. EPA, environmental groups and several states filed suit against the Phase II regulation alleging that the decision to not require closed-cycle cooling violated the Clean Water Act. In 2007, the Second Circuit Court ruled that the use of cost–benefit analysis to determine best technology available (BTA) is inadmissible under Section 316(b) and remanded several provisions of the rule. EPA subsequently suspended the Phase II regulations.[42]

After appeals by EPA and industry, the case went to the Supreme Court, which in April 2009 reversed and remanded the Second Circuit's decision, allowing the BTA to be determined by cost–benefit analysis.[43] The Supreme Court ruling did not hold that 316(b) *requires* cost–benefit analysis, only that it could be used.

At present, EPA's earlier regulations remain suspended, which means that compliance determinations are being decided on a case-by-case basis by the permitting authority, usually the state. EPA's new proposed rulemaking on March 28, 2011 will address these and other issues from court rulings on the earlier Phase I, II, and III rulemakings. Under the Clean Water Act's Section 316(b), EPA has considerable discretion with respect to the application of cooling water constraints that minimize entrainment and impingement, and the Agency's recent proposal draws on this flexibility.

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[37] 33 U.S.C. § 1326(b).

[38] Impingement is when fish are pinned against water intake screens or other parts at the facility. Entrainment is when aquatic organisms are drawn into cooling water systems.

[39] For more information see U.S. EPA. Water: Cooling Water Intakes (316b). Basic Information. http://www.epa.gov/waterscience/316b/basic.htm. Phase II addresses large existing power plants that are designed to withdraw 50 million gallons per day or more and that use at least 25 percent of their withdrawn water for cooling purposes only.

[40] Affected facilities have a design intake flow threshold of greater than 2 million gallons per day and withdraw at least 25 percent of water for cooling purposes. See http://www.epa.gov/waterscience/316b/phase3/ph3-final-fs.html.

[41] *Entergy Corp. v. Riverkeeper, Inc*. 556 U.S. (2009)

[42] 72 FR 37107

[43] Ibid.

Under the Clean Water Act's Section 316(b), EPA has considerable discretion with respect to the application of cooling water constraints that minimize entrainment and impingement.

Facilities with design intake above 2 million gallons per day, that withdraw at least 25 percent of their water from an adjacent water body for cooling, must submit information and limit the number of fish killed by being pinned against intake screens or equipment (impingement) and sucked into the water intake system (entrainment). Many existing facilities may have to install screens, make modifications to existing technology or take measures to reduce intake velocity. The EPA proposal includes additional requirements for facilities that use very large quantities of water (i.e., actual water intake above 125 million gallons per day). Facilities that exceed this threshold must submit additional information regarding entrainment, including a study that compares the costs and benefits of installing a cooling tower versus alternative technology. Lastly, the proposed water rule requires the use of cooling towers, or their equivalent, for any new unit capacity additions built at an existing facility (the requirement does not apply to capacity replacements).

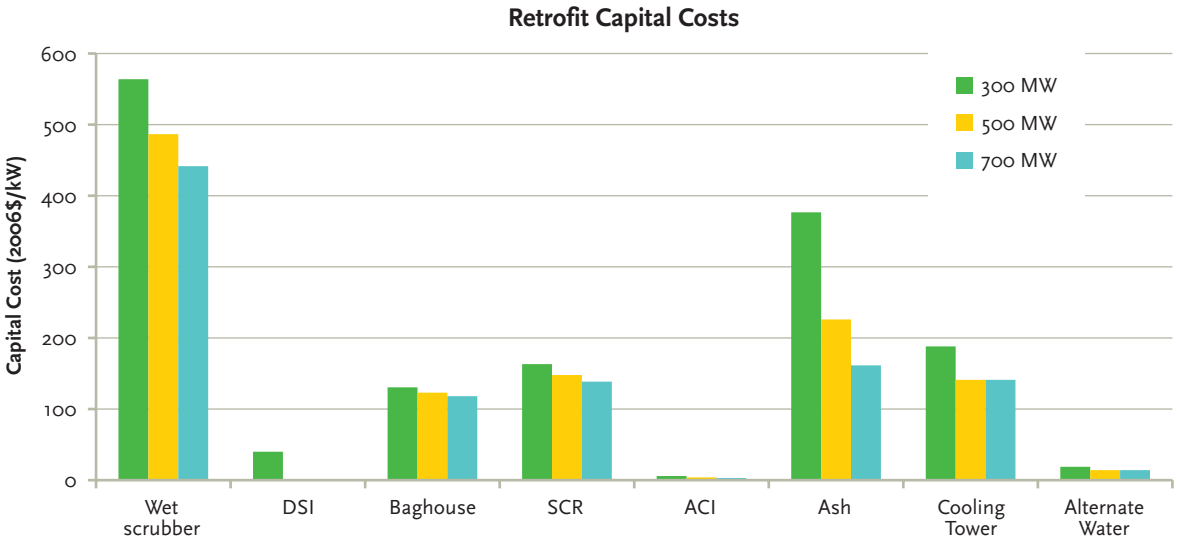
RELEVANT POLLUTION CONTROL TECHNOLOGIES

Although many existing plants will comply with some or all of the various EPA regulations based on their current configuration and already installed controls, some will require new pollution controls. Table 2 identifies some of the control technologies expected to be used for compliance with upcoming EPA regulations.[44] Figure 5 compares the relative capital cost to install such technologies on existing electric generating units.

EPA REGULATIONS AND RELIABILITY CONCERNS

The timeline for forthcoming EPA regulations has prompted concern that grid reliability issues could arise in some parts of the country as utilities comply with pollution regulations. These concerns center on the combined effects of new EPA rules on plant retrofits and retirements and on the condensed compliance timeline for the Utility Air Toxics Rule, in particular. Figure 6 lays out a likely timeline for compliance with these regulations. The figure shows that 2014 and 2015 are likely to be the most constrained years as power plant owners prepare to comply with the Air Toxics Rule.

FIGURE 5. ESTIMATED RETROFIT CAPITAL COSTS OF RELEVANT TECHNOLOGIES



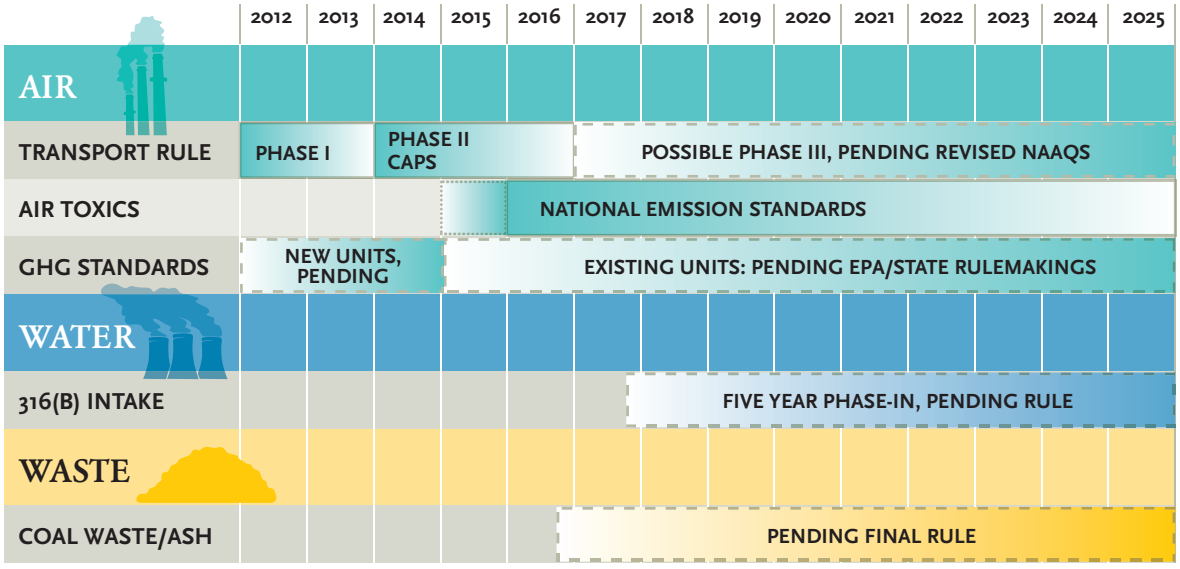
Note: The capital cost of a dry scrubber is estimated to be 10-20% lower than that of a wet scrubber.
DSI costs are shown for units less than or equal to 300 MW, based on BPC conservative modeling assumption to only offer DSI for such smaller units burning low sulfur coal.
Source: Technology capital cost assumptions used in BPC modeling of EPA Regulation scenarios.

[44] For additional information about control technologies see Lipinski, G., J. Leonard, C. Richardson. Assessment of Technology Options Available to Achieve Reductions of Hazardous Air Pollutants. URS Corporation. April 2011.
Staudt, James E. and M.J. Bradley & Associates. Control Technologies to Reduce Conventional and Hazardous Air Pollutants from Coal-Fired Power Plants. March 31, 2011.
Fessenden, Jamie. NESCAUM (Boston, MA). Multi-pollutant Emission Reduction Technology for Small Utility Boilers. Presentation to Lake Michigan Air Directors Consortium, Innovative Industrial Source Control and Measurement Technologies Workshop. March 24, 2010.

TABLE 2. EPA REGULATION AND EXPECTED CONTROL TECHNOLOGIES

Pollutant/Issue	Control Technologies/Measures
Acid Gases:[45] Air Toxics HCl & HF, plus Sulfur Dioxide (SO_2)	Wet scrubber *or* Dry scrubber + Particulate Controls *or* Dry Sorbent Injection (DSI) + Particulate Controls
Metallic Toxics/Particulate Matter	Baghouse/Fabric Filter *or* Electrostatic Precipitator (ESP)
Mercury	Activated Carbon Injection (ACI) + Particulate Controls *or* Wet scrubber + Selective Catalytic Reduction (SCR)
NO_x	Selective Catalytic Reduction (SCR) *or* Selective Non-Catalytic Reduction (SNCR), low-NO_x burners, etc
Coal Ash	Dry ash handling + ash pond liners, etc
Cooling Water Intake	Screens, barrier nets, low velocity caps, etc *or* Cooling Tower
GHG Performance Standards	Efficiency upgrades or, potentially, biomass co-firing

FIGURE 6. TIMELINE OF EPA REGULATIONS IMPACTING THE POWER SECTOR



[45] The acid gases hydrogen chloride (HCl) and hydrogen fluoride (HF) are regulated under Section 112 of the Clean Air Act. By contrast, SO_2 is regulated as a conventional "criteria" pollutant under the NAAQS provisions of the Act.

SECTION
III

RESULTS OF POWER SECTOR ANALYSIS

A. CURRENT TRENDS IN THE POWER SECTOR

As has already been noted, a number of market factors are likely to lead to the retirement of a significant number of coal-fired power plants, even absent EPA regulation. These include:

- Aging coal-fired power plants. About 33 percent of the existing coal-fired fleet is over 40 years old, and most of this aging capacity lacks environmental controls. These units tend to be small and relatively inefficient, and therefore do not operate near full capacity. These units are likely to become increasingly uneconomic.

- Low gas price projections. Recent advances in drilling technology for natural gas have lead to a dramatic reassessment of the magnitude of potentially available U.S. natural gas resources, and an associated decline in projected prices. Although coal-fired power plants have historically enjoyed a cost advantage over natural gas-fired plants, this cost advantage is diminishing, and older, inefficient plants are likely to become increasingly uneconomic as a result of gas prices alone.

- Ongoing uncertainty about the future regulation of carbon dioxide (CO_2) makes it even less likely that companies will invest in aging plants.

Consideration of these factors alone has led some analysts to project significant coal plant retirements over the next decade, even absent EPA regulation. For example, EEI's January 2011 analysis projected 22 GW of coal retirements in the reference case (i.e., with no new regulation) by 2015. In its October study, NERC reported that 13 GW of upcoming retirements were already announced or committed, prior to EPA's proposals for Utility Air Toxics and cooling water rules.[46]

This section summarizes the projected impacts of forthcoming EPA regulations on retirements in the power sector. In particular, it reviews findings from several existing studies along with some key underlying assumptions, with a focus on results pertaining to plant retirements and implications for resource adequacy.

BPC review of existing studies and our own modeling suggests that the actual number of retirements due to EPA regulations will be at the lower end of the range of published projections.[47] This is primarily because most analyses assume that the EPA regulations (particularly 316(b) and Utility Air Toxics) will require much more costly controls than EPA's recent proposals indicate. Analyses of resource adequacy also tend to use these retirement projections in combination with capacity projections that do not reflect how market drivers will influence the construction of additional capacity (or demand side management). As a result, these studies are likely to overstate risks to resource adequacy.

B. STUDIES ON THE IMPACT OF EPA REGULATIONS

A number of studies, compared in Table 3, have evaluated the potential retirements that are likely to result from market conditions and forthcoming EPA regulations. These studies vary in terms of the regulations they cover; the assumptions they make about the stringency, timing, and cost of regulations; and the general methodology and other market assumptions they apply. It is important to consider the implications of each of these factors.

Because some studies do not include an estimate of "business-as-usual" (BAU) retirements in the absence of EPA regulations, and because the studies make different assumptions about electricity demand, fuel prices, and other variables that impact the number of retirements in the baseline case, it is not possible in many cases to determine the incremental number of retirements being projected as a result of EPA regulations. Therefore, BAU retirements are included in the total coal retirements reported in the table below.

REGULATIONS COVERED

Studies have also differed with respect to the scope of environmental regulations examined. A number of studies look only at the potential impact of upcoming air emissions rules (e.g., the Transport Rule and Utility Air Toxics Rule), while others also evaluate the impact of regulatory scenarios for cooling water, coal ash, tighter NO_X requirements to incorporate NAAQS revisions, and/or future greenhouse gas constraints. EPA's modeling for the Utility Air Toxics Rule, the CRA and PIRA studies, and some of the EIA AEO2011 EPA regulation sensitivity runs, are all limited to the Transport Rule and Utility Air Toxics Rule. The Credit Suisse analysis and an EIA AEO2011 run include tighter NO_X requirements beyond the Transport Rule, while the Brattle Group also looks at a scenario that includes the water rules. The modeling from BPC and EEI referenced in Table 3 includes EPA rules on air (Transport Rule, Utility Air Toxics Rule, and future NO_X), water, and ash. The ICF analysis quoted in the table includes air, water, and ash, plus a CO_2 price.

Based on a review of studies and internal BPC analysis, as well as recent EPA proposals, we conclude that the most important *regulatory* driver of projected coal plant retirements, and hence of possible reliability concerns, is the Utility Air Toxics Rule. But other non-regulatory factors, including low natural gas prices, may be as important. The uncertainty regarding future carbon constraints, even without an immediate regulatory driver, is also significant as it may lead some plant operators to forego life-extending pollution control investments on inefficient coal plants. Cooling water and ash regulations will increase costs for some facilities, but are not expected

[46] North American Reliability Corporation. 2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations. October 2010. Page 8.

[47] See Appendix B for additional information about BPC modeling using ICF's Integrated Planning Model.

TABLE 3. COMPARISON OF COAL RETIREMENTS FROM SELECTED STUDIES AND SCENARIOS

Study	Regulations Included	Projected Retirements	Details
EIA AEO2011 April 2011	TR, Mercury TR, Air Toxics, NO_x	**14-18 GW total** **19-45 GW total**	The high ends represent retrofit cost recovery in 5 yrs vs 20. "TR, Air Toxics, NO_x" assumes wet FGD & SCR on each unit. Nat gas price below AEO2011 (≈$4/mmBtu) brings second case retirements up to 40-73 GW.
EPA March 2011	TR, Toxics	**23 GW total** (including 10 GW incremental)	Modeling for Utility Air Toxics Rule (Toxics) proposal; Transport Rule (TR) included in the baseline and not in the incremental retirements.
BPC March 2011	TR, Toxics, Coal Ash, 316(b), NO_x	**29-35 GW total** (15-18 GW incremental)	Assumes ACI, Fabric Filter and either wet FGD or DSI for Utility Air Toxics Rule. DSI only for units <300 MW with low sulfur coal. Cooling towers if >500 MGD design intake. Stricter NO_x by 2018. Low end of the range results from higher AEO2010 natural gas price.
EEI January 2011	TR, Toxics, Coal Ash, 316(b), NO_x	**46-56 GW total** (24-34 GW incremental)	Low end estimates reflect availability of lower cost compliance strategies for some units. EEI scenarios that include CO_2 price are excluded.
CRA December 2010	TR, Toxics	**39 GW total** (includes 6 GW planned retirements)	Assumes ACI, fabric filter, and FGD for Utility Air Toxics Rule. Assumes AEO2010 natural gas price.
Brattle Group December 2010	TR, Toxics TR, Toxics, 316(b), NO_x	**40-55 GW total** (34-49 GW 2020 incremental) **50-66 GW total** (44-60 GW 2020 incremental)	Doesn't identify specific assumptions for each rule, but assumes SCR and scrubber on every coal unit by 2015. Cooling towers on all coal units by 2015 for 316(b).
ICF December 2010	TR, Toxics, Coal Ash, 316(b), NO_x, +CO_2 price	**70 GW total** by 2018 (including 10 GW of announced retirements)	For Utility Air Toxics Rule, scrubber, ACI, and baghouse assumed for all units. For 316(b), cooling towers on units drawing from coastal and estuarine water bodies. Retirement estimates also reflect cap-and-trade program for CO_2 emissions that begins in 2018.
NERC October 2010	TR, Toxics, 316(b), Coal Ash	**10-35 GW** by 2018 (excludes 13 GW committed/ announced retirements, which may include non-coal units)	Range reflects 'Moderate' and 'Strict' scenarios. Both assume cooling tower required for 316(b) the primary driver of retirements. For Utility Air Toxics Rule, both assume FGD (with SCR, or ACI + baghouse).
Credit Suisse September 2010	TR, Toxics, NO_x	**60 GW total**	Assumes retirement of all small plants without SCR or FGD, and half of small plants with SCR but no FGD.
PIRA April 2010	TR, Toxics	**30-40 GW total**	This analysis was quoted in a study by MJ Bradley/ Analysis Group.

Note: Coal retirement estimates are reported for 2015 if available. Total coal plant retirements, including those already announced and projected in the reference case, even absent EPA regulations, are reported, where available. Where available, incremental retirements resulting from the EPA rules are reported in parentheses.

Sources:

- U.S. Energy Information Administartion. Annual Energy Outlook 2011 With Projections to 2035. DOE/EIA-0383(2011). April 2011. Page 4. http://www.eia.gov/forecasts/aeo/pdf/0383(2011).pdf
- U.S. Environmental Protection Agency. Regulatory Impact Analysis for the Utility MACT Proposed Rule. March 2011. http://www.epa.gov/ttn/atw/utility/utilitypg.html
- Edison Electric Institute, with analysis performed by ICF International. Potential Impacts of Environmental Regulation on the U.S. Generation Fleet. January 2011.
- Charles River Associates. A Reliability Assessment of EPA's Proposed Transport Rule and Forthcoming Utility MACT. December 2010.
- Brattle Group. Potential Coal Plant Retirements Under Emerging Environmental Regulations. December 2010.
- ICF International. ICF 2010 Quarter 4 Integrated Energy Outlook: Summary of Analysis Results. December 2010.
- North American Reliability Corporation. 2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations. October 2010. (page 63 coal retirements plus page 8 committed/announced.)
- Credit Suisse. Growth from Subtraction: Impact of EPA Rules on Power Markets. September 2010.
- PIRA. EPA's Upcoming MACT: Strict Non-HG Can Have Far-Reaching Market Impacts. April 2010.

to have a strong influence on reliability because of long compliance periods and low numbers of retirements, beyond those units expected to retire due to other factors. For example, in their most stringent scenario, the NERC study estimates that only 388 additional MW retire as a result of the ash rule alone; EEI's most stringent scenario for ash retires an incremental 6 GW by 2020.[48] The impact of future NO_X rules, which are yet to be proposed, will depend on how those rules are designed.

STRENGTH AND TIMING OF REGULATIONS

Generally, the available studies assume that EPA will promulgate regulations at the stringent end of the spectrum of what is possible. This assumption proved least accurate in the case of the 316(b) cooling water proposed requirements, which were signed March 28, 2011, after the referenced studies were undertaken.

Those studies generally assumed that EPA's rule would require all units to install cooling towers and move to closed cycle cooling systems. This assumption–which was not borne out in EPA's actual proposal–adds as much as 40 GW of plant retirements to the projected outcome in some analyses.

According to EPA, an estimated 70 percent of existing facilities are not expected to require a cooling tower under the new rule because their actual intake flow is below the threshold of 125 million gallons per day (MGD) and EPA expects lower cost screens and intake velocity measures to allow compliance with impingement mortality limits.[49,50] Even for facilities with actual intake above 125 MGD, EPA's proposed rule would require a cooling tower only if the state permitting authority made a site-specific determination that alternatives would not be adequate and also demonstrated that the benefits of a cooling tower outweigh the costs. Given typical valuations of fish death and ecosystem damage, it may prove difficult for states to demonstrate that benefits outweigh the cost of a new cooling tower, particularly if such a requirement would lead a plant to retire.

Furthermore, the proposed rule requires states to consider the remaining useful life of the affected facility and any electric reliability impacts. Considering that the units most vulnerable to retirement are generally well past 40 years old, it seems even less likely that a case-by-case determination would require a cooling tower installation (with a deadline of 2022 for fossil units) on plants that would be, by then, another decade older than they are today. Thus, many of the remaining 30 percent of units which are subject to a cooling tower study may comply with less expensive alternatives and the 316(b) rule may not lead to significant retirements.

The EEI study includes a sensitivity run "Alternative Water Case," which requires cooling towers on a subset of existing units with design intake flow above 125 MGD that draw water from oceans, estuaries, and tidal rivers. Even this case, however, is likely more stringent than the EPA water rule. First, the EPA threshold is based on actual intake flow. By contrast, the EEI study used design intake flow–which is often considerably higher–as the threshold to determine which units might be affected. Second, even for facilities with actual intake flows above the EPA threshold, the state case-by-case determination is likely to avoid a cooling tower requirement for at least some, if not most, facilities.

The referenced analyses also vary in terms of their assumptions about when cooling towers would be required. The NERC study appears to have the most aggressive timing assumptions. It assumes 316(b) will require cooling towers on all nuclear and fossil units by 2018. NERC projected that the 316(b) rule alone would result in about 40 GW of retirements by 2018. The EEI study maintains the assumption that cooling towers are broadly required on existing units, but delays compliance until 2020 for fossil units and 2027 for nuclear units.[51] As actually proposed, the EPA rule requires impingement controls, such as screens to be in place by 2020. If cooling towers are required, compliance is required by 2022 or 2027 for fossil and nuclear plants, respectively.

An additional variable related to regulatory stringency involves the expectation of deeper NO_X reductions beyond the first and second phases of the Transport Rule. Some analyses (including EIA, Brattle Group, Credit Suisse, and most EEI scenarios) assume that all units will be required to install selective catalytic reduction (SCR), the most costly control technology for NO_X. However, many units are expected to meet their compliance obligations–under the Transport Rule for units in the East and under Best Available Retrofit Technologies (BART) requirements in the West – using lower cost technologies, such as selective non-catalytic reduction (SNCR) or low

[48] EEI. Potential Impacts of Environmental Regulation on the U.S. Generation Fleet. January 2011. Page 13.

[49] Federal Register Notice pre-publication. U.S. EPA Proposed Rule for Cooling Water Intake Structures, Section 316(b), Clean Water Act. March 28, 2011. Page 86.

[50] However, industry sources have expressed concern that site-specific factors or permitting decisions may lead to cooling towers to reduce impingement and entrainment mortality at facilities below the threshold.

[51] EEI specifies water policy assumptions of cooling towers required by 2022 for fossil and 2027 for nuclear. However, the IPM version supporting their analysis does not include a model year for 2022 and EEI chose to map the 2022 compliance date to the years 2020. EEI. Potential Impacts of Environmental Regulation on the U.S. Generation Fleet. January 2011. Page 12.

NO_X burners. Beyond the current Transport Rule, future NAAQS revisions are expected to tighten NO_X control requirements, but there is little indication that SCR would be required on all units nationwide.

TECHNOLOGY AND COST ASSUMPTIONS

Existing studies make different assumptions about the capital and operating costs of pollution control technologies and about the costs of providing replacement capacity. Moreover, these assumptions are not always clearly and explicitly identified even though they play an important role in determining the number of retirements projected. All else equal, studies that assume higher control costs predict higher levels of retirements.

A major discrepancy between various analyses is the assumed cost of compliance with Utility Air Toxics Rule limits for acid gases. This has a notable effect on their findings with respect to number of retirements, retrofits, and price impacts. With the exception of EPA, BPC, and two sensitivity runs in the EEI analysis, all other studies assume that compliance with acid gas limitations in the Utility Air Toxics Rule will require a scrubber–the most expensive control technology related to the suite of upcoming EPA regulations–by 2015. By contrast, EPA's analysis in support of its Utility Air Toxics Rule includes DSI, in combination with particulate controls, as a compliance option to achieve acid gas limits. EPA's assumed costs for DSI are based on a detailed engineering cost analysis.[52]

BPC analysis also assumes that DSI, in combination with a fabric filter, is an option to comply with the acid gas Utility Air Toxics Rule standard, but BPC makes a conservative assumption to limit DSI to smaller units less than 300 MW that burn low sulfur coal. The NERC analysis as well as the main policy scenarios in EEI's January 2011 analysis do not allow compliance with DSI and instead require a scrubber on every unit for compliance with the Utility Air Toxics Rule. EEI does include a sensitivity run "Alternative Air Case" that allows dry sorbent injection to comply with the acid gas limit for smaller units less than 200 MW. According to the EEI analysis, the availability of DSI as a compliance option reduces expected cumulative coal retirements in 2015 by 10 GW.

FUEL PRICE ASSUMPTIONS

Fuel price assumptions for coal and natural gas will also impact the economics of individual plants. Because natural gas-fired capacity competes with coal-fired capacity, lower natural gas prices lead to the displacement of coal-fired generation in the reference case, and result in older, less-efficient coal plants becoming uneconomic.

MARKET RESPONSE

Studies vary in how they simulate the electricity market. Some studies (e.g., NERC, Brattle) do a static analysis of facilities that are at risk of retirement, comparing projected operating costs under the regulation (using generic cost factors and fuel price projections) with expected revenue based on forward electricity price projections. However, these studies do not account for the impact of the regulations themselves on electricity or fuel prices. For example, electricity prices are expected to rise as a result of the regulations, such that expected revenues will likely be higher than projected. This feedback effect would likely reduce the number of expected retirements. Other studies (EEI, EPA, and BPC) utilize dynamic power sector models that attempt to capture the effect of changing electricity and fuel prices on the cost of generation.

COMBINED SCENARIOS

With the exception of the BPC analysis, EEI's sensitivity scenarios–the "Alternate Air Case" and the "Alternative Water Case"–come closer to modeling the actual requirements and technology options for recently proposed EPA regulations than do the other referenced studies. However, EEI's analysis does not include a scenario that approximates the actual proposals for both the Utility Air Toxics Rule and the cooling water proposals together. Instead, the "Alternative Air Case" includes more stringent water requirements and the "Alternative Water Case" does not allow for lower cost air controls consistent with EPA's new regulations as recently proposed. *Thus, most of the referenced studies probably overstate the cost and number of retirements likely to be associated with forthcoming EPA regulations.*

BPC analysis using ICF's Integrated Planning Model used many assumptions similar to the EEI study (see Appendix B). The BPC analysis includes a scenario that allows for some of the lower cost Utility Air Toxics Rule controls (i.e., dry sorbent injection instead of a scrubber for units less than 300 MW) and less stringent water requirements (i.e., cooling towers on facilities which draw more than 500 MGD and operate above 35% capacity factor). These BPC assumptions, result in 20-25 GW of DSI installations instead of scrubbers as well as cooling tower installations on 93 facilities (no

[52] Sargent & Lundy. IPM Model – Revisions to Cost and Performance for APC Technologies: Dry Sorbent Injection Cost Development Methodology. August 2010. Found at http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/append5_4.pdf.

incremental retirements are projected from the water rule).[53] BPC assumptions result in a projected 15-18 GW of incremental coal plant retirements by 2015 from the suite of EPA regulations, with no additional incremental retirements through 2030. When factoring in BAU retirements in the reference case (14 GW of coal and 23 GW of oil/gas BAU retirements), the BPC analysis results in 57-58 GW of overall retirements by 2030.

C. IMPACTS OF RETIREMENTS ON RESOURCE ADEQUACY

Plant retirements alone are not the only factor to consider in evaluating the system reliability impacts of environmental regulation. Another relevant issue is resource adequacy, or the extent to which expected available generation resources will be capable of meeting forecasted demand. Planning authorities evaluate resource adequacy periodically, generally by assessing reserve margin levels and loss of load expectation (LOLE) for the relevant location.[54] Resource adequacy is a useful metric for planning purposes, though it provides limited insight into operational reliability (operational reliability is the ability to serve all customers at all locations at all times of day). Operational reliability depends not only on capacity availability, but on conditions in local transmission and distribution systems.

Where existing capacity surpluses are not sufficient to maintain reserve margin requirements in the presence of retirements, new capacity will have to be added to maintain resource adequacy. This new capacity could be in the form of new generation or demand side resources. In competitive markets, higher spot market prices and forward capacity markets will provide an incentive to construct new capacity. In regulated markets, the requirement to submit integrated resource plans for approval serves as a vehicle for identifying new capacity needs and planning accordingly.

Existing analyses vary in the way that they assess the issue of new capacity and apply the methodology and analytical tools at hand. For example, some electricity sector models inherently assume that all of the necessary capacity resources will be constructed in order to meet reserve margin requirements.[55] While such modeling cannot be used to directly draw conclusions about resource adequacy or reliability, the amount of new capacity projected to be built in response to retirements and other market changes can be instructive. This type of modeling can shed light on how much capacity will be needed, and in what timeframe, to maintain resource adequacy. For example, the January 2011 EEI analysis projects that 7 to 18 GW of incremental new capacity will be required nationally by 2015 due to the suite of EPA regulations–this is in addition to 66 GW of new capacity in the base case.[56] These capacity projections fall well within the realm of what the industry has constructed in recent periods. A CRA study found that over the period 1999–2004, the industry constructed 177 GW of natural gas-fired capacity alone.

A handful of the studies discussed in the table above attempt to make the link between projected retirements and implications for resource adequacy. By comparing projected retirements in specific regions against projected reserve margins, these studies attempt to highlight areas where there could be capacity shortfalls if adequate planning and new capacity construction does not occur.

- With respect to the Utility Air Toxics Rule, EPA concludes that projected coal plant retirements "are not expected to raise broad reliability concerns" and points to the existence of sufficient excess capacity to take up the slack for projected retirements, which the Agency estimates will total less than 10 GW. EPA calculates that the Utility Air Toxics Rule will reduce the national weighted average reserve margin by just a few percent below the 25 percent reserve margin level projected in the baseline scenario. This compares to a NERC recommended reserve margin of 15 percent. According to EPA modeling, resource adequacy is maintained in each region where coal retirements occur primarily by using excess reserve capacity and by "reversing base case retirements of non-coal capacity, building new capacity, or importing excess reserve capacity from other regions."[57] For the water

[53] For comparison, EPA modeling for the proposed water rule includes scenarios of cooling tower installations ranging from 46 facilities – affecting only baseload and load-following facilities – to 76 facilities, including the largest fossil plants that draw from tidal waters.

[54] The reserve margin is calculated as the difference between available generation capacity and expected peak demand, divided by peak demand. Sometimes calculated reserve margins are compared against region-specific North American Electric Reliability Corporation (NERC) Reference Reserve Margin levels or, if a regional reference level is not provided, against reserve margins assigned by NERC based on capacity mix. LOLE measures the number of days per year that available resources will be insufficient to serve peak daily demand; this is typically assessed through probabilistic modeling. NERC recommends an LOLE of 0.1, which implies that the system may fail to serve peak load no more than 1 day in 10 years.

[55] EPA, EEI, and BPC all use ICF's Integrated Planning Model to make these assessments. The ICF planning model assumes that all necessary capacity resources will be constructed as needed to meet reserve margins.

[56] These numbers are incremental to the capacity additions that are projected under the reference case by 2015. The projections cited here do not include EEI scenarios that included a price on CO_2 emissions.

[57] U.S. EPA. Regulatory Impact Analysis for the Utility Air Toxics Rule proposed rule. March 29, 2001. Found at: http://www.epa.gov/ttn/atw/utility/utilitypg.html. Page 234-236.

[57] U.S. EPA. Utility Air Toxics Rule Information Collection Request. Regulatory Impact Analysis for the Utility MACT proposed rule. Found at: http://www.epa.gov/ttn/atw/utility/utilitypg.html. March 29, 2011. Page 234-236.

rule, EPA made an overall determination that none of the technology options would cause unacceptable reliability concerns at the national level. But to avoid concern at individual sites, the rule will require permitting authorities to consider reliability impacts in their case by case determinations.[58]

- A December 2010 analysis by The Brattle Group, which assumes that scrubbers, SCR, and cooling towers are required on all plants by 2015, finds that reserve margins would fall below NERC reference levels in 2018 in the Reliability First Corporation (RFC) region (which includes parts of the Mid-Atlantic and the eastern Midwest) and in the Electric Reliability Council of Texas (ERCOT) region if new resources are not added.[59]

- CRA evaluated expected 2015 capacity at the level of regional transmission organizations (RTOs), NERC regions, and NERC sub-regions in comparison with reserve margin requirements for that year. At the RTO level, the study found that all regions with projected retirements were expected to meet and exceed reserve margin requirements in that year. At the NERC region level, the CRA study found modest reserve margin shortfalls in the Midwest Reliability Organization (MRO) region, and de-minimis shortfalls in the RFC and Southeast Reliability Corporation (SERC) regions. Looking at the NERC sub-region level, CRA found that the greatest potential resource adequacy impact was likely to occur in the Virginia-Carolinas (VACAR) subregion of SERC. However, nearly half of the projected capacity needed for this region is already in planning stages, but was excluded from the analysis. The CRA study concluded that a combination of coal-to-gas conversions, new gas-fired generation, load management, and existing market and regulatory safeguards would be sufficient to maintain reliability.

- The NERC study estimated that 10 to 35 GW of coal-fired capacity could be at risk of retirement by 2018, when factoring in the Transport Rule, Utility Air Toxics Rule, Coal ash, and 316(b) rules. It is important to note that NERC's aggressive assumption for 316(b) is the biggest driver of retirements, even in NERC's 'moderate' case.[60] Comparing projected retirements under its moderate case against NERC region-level estimates of capacity resources, the NERC study identified SERC as the region most at risk of capacity shortfalls. The study also identified potential capacity shortages in Arizona and New Mexico, and in the southern Nevada sub-region of the Western Electric Coordination Council (WECC). When more conservative (lower) estimates of available capacity resources are used, NERC projects potential shortages in those regions, as well as in the MRO region, New England, Texas, and the Rocky Mountain Power Area.[61] According to NERC, building new capacity, or advancing in-service dates of planned capacity additions, could help to alleviate projected losses.[62] In addition, NERC's updated 2010 demand forecasts and planned new capacity additions were not incorporated into their special assessment of EPA regulations and would have trended toward greater capacity reserves.

- The MJ Bradley and Analysis Group report notes that "the electric sector is expected to have over 100 GW of surplus generating capacity in 2013, about three times the 30 to 40 GW of total retirements projected by PIRA Energy Group" (in its analysis of the impact of the CATR and the Utility Air Toxics Rule).[63] This is largely due to much slower than expected demand growth resulting from the recession. The report further notes that the RFC and SERC regions, where expected retirements are greatest, are projected to have reserve margins of 24.3 percent and 26.3 percent respectively. Again, these figures are well above the 15 percent Reference Margin Level that NERC assigns to most regions.

While most studies have taken a national approach to the reliability assessment, it is clear that some regions will be more vulnerable during this transition period. More study is warranted to assess localized reliability impacts in the most vulnerable regions.

D. THE STAGING OF RETROFITS

Although reliability concerns have mostly focused on plant retirements, there are also concerns about the ability of affected sources to install control technologies in time to meet compliance deadlines–particularly for the Utility Air Toxics Rule –and about the implications

[58] Federal Register Notice pre-publication. U.S. EPA Proposed Rule for Cooling Water Intake Structures, Section 316(b), Clean Water Act. March 28, 2011. Page 55.

[59] For a map of NERC regions, see http://www.eia.doe.gov/cneaf/electricity/chg_str_fuel/html/fig02.html.

[60] In both the moderate and strict cases, NERC assumes cooling towers on all facilities, 25 percent higher costs are assumed for the strict scenario.

[61] NERC compares potential retirements in individual regions against Summer Peak Deliverable capacity Resources and Summer Peak Adjusted Potential Capacity Resources. The former is the more conservative estimate.

[62] NERC. 2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations. October 2010. Page V.

[63] M.J. Bradley & Associates LLC and Analysis Group. Ensuring a Clean, Modern Electric Generating Fleet While Maintaining Electric System Reliability. August 2010. Referencing NERC. 2009 Long-Term Reliability Assessment: 2009-2018. October 2009. And PIRA Energy Group ("PIRA"). EPA's upcoming MACT: Strict Non-Hg Can Have Far Reaching Market Impacts. April 8, 2010.

for consumer costs. Some fear that the need to install large numbers of controls on a system-wide basis in a relatively short timeframe could lead to constraints in financing or materials, which in turn could drive up the cost of compliance.

In its Regulatory Impact Analysis for the proposed Utility Air Toxics Rule, EPA predicts the rule will lead to the installation of scrubbers on an additional 24 GW of capacity; the application of DSI to an additional 56 GW of capacity; the application of ACI to an additional 93 GW of capacity; and the use of SCR on an additional 3 GW of capacity.[64] In addition, EPA predicts that additional fabric filter retrofits will be installed on 49 GW of capacity to comply with the Utility Air Toxics Rule –this is on top of fabric filter installations to meet other Clean Air Act requirements, for a total of 165 GW of capacity with new fabric filters by 2015.[65] Because EPA's assessments project fewer retirements than other studies, they generally project the highest number of control installations. However, installations required before the 2012 and 2014 Transport Rule caps take place are not included in the cited EPA Utility Air Toxics Rule retrofit estimates. In addition, because EPA has more bullish assumptions about DSI, they project fewer scrubbers and more DSI than either the BPC or EEI analyses assume. BPC projects up to 51 GW of scrubbers may be constructed in 2013, 2014, and 2015, in addition to 24 GW of DSI.

Once permitted, most pollution control projects can be implemented in less than two years from design to start-up without the need for outage or with the final step occurring during a regularly scheduled maintenance period, so as to avoid additional outage time. According to a recent report, installing scrubber systems can require from two to three years for a dry system and 24 to 44 months for a wet system from the design through construction stage.[66, 67] The high end of the range is typically associated with more challenging installations due to site-specific limitations. Plants generally continue to operate throughout most of this time, but the final step of "tying in" or connecting the scrubber system typically requires that the plant be shut down for four to eight weeks. Often this step can be completed during a regularly scheduled maintenance outage.

Rate recovery determinations and permitting processes can add to these timeframes. A number of states have avoided a time crunch by passing legislation and/or by entering into agreements with power companies that provide for early planning, timely rate recovery decisions, and a schedule for control installations and retirements. In areas that have not taken such anticipatory steps, however, waiting until after the final Utility Air Toxics Rule is signed in November 2011 to begin a lengthy approval process may be problematic, particularly if site-specific challenges have the effect of complicating scrubber installations and extending the time required to complete needed pollution control retrofits. This highlights the need for plants to immediately begin planning and designing for pollution controls.

None of the economic analyses undertaken to date have directly addressed the issue of staging retrofits. Nevertheless, insufficient planning and coordination between generating companies and state, regional, and federal institutions could result in higher than necessary costs for consumers. For example, if a large number of companies delay retrofits until close to the deadline in order to defer capital costs as long as possible or waiting for state approvals, numerous retrofits may be scheduled in close proximity, leaving the grid potentially vulnerable to supply disruptions if multiple plants go off line at the same time. This could result in higher electricity prices as more costly generation resources are dispatched to supply electricity. Section IV of this report discusses some possible strategies that could be used to manage the timing and coordination of pollution control retrofits.

[64] U.S. Environmental Protection Agency. Regulatory Impact Analysis for the Utility Air Toxics proposed rule. March 29, 2011. Found at: http://www.epa.gov/ttn/atw/utility/utilitypg.html. Page 8-13.

[65] Ibid.

[66] See Lipinski, G., J. Leonard, C. Richardson. Assessment of Technology Options Available to Achieve Reductions of Hazardous Air Pollutants. URS Corporation. April 2011. Particulate upgrades can be completed in 12-24 months with an outage of less than 2 weeks, or up to 4 weeks if a new fan is required for a Fabric Filter upgrade (page A-3). ACI requires up to eighteen months, but no outage time (page A-9). DSI requires nine to twelve months from design to start-up, but no additional outage (page A-11).

[67] Because the formula for the Air Toxics regulation was mandated in the 1990 Clean Air Act, many companies have already begun the planning, design and, in some cases permitting and construction for pollution control equipment, in advance of the final rulemaking. Companies will have 45 months, with the opportunity to ask for a one year extension that allows 57 months, from the March 2011 Utility Air Toxics Rule proposal until the compliance deadline. Some companies say it takes an average of 54 months to install a scrubber and 4-5 years to install a baghouse, including planning, design, permitting/regulatory approval, constructing, and start-up of the control device.

SECTION
IV

ADDRESSING RELIABILITY CONCERNS: THE ROLES OF FEDERAL, STATE, AND REGIONAL AUTHORITIES

Federal, regional, and state institutions will play a key role in ensuring reliability as the electricity sector transitions to a new regulatory regime. These organizations have a variety of authorities and tools at their disposal to ease the transition and to help avoid significant impacts on reliability. This section describes the roles of various authorities in addressing reliability issues associated with new environmental requirements.

A. FEDERAL AGENCIES

ENVIRONMENTAL PROTECTION AGENCY

EPA provides analytical and technical support to regulated entities, state authorities, and other federal agencies in planning for and implementing new environmental regulations. In addition, Congress usually grants the Agency specific authorities and discretion in the implementing legislation for each major rulemaking, which are described below.

EPA Discretion on the Utility Air Toxics Rule

Although the Utility Air Toxics Rule is largely prescriptive, EPA does have some discretion to provide flexibility on certain provisions. The following provisions were included in the March 15, 2011 proposed Utility Air Toxics Rule and should be included in the final rule:

- Emissions averaging among units at a facility within the same sub-category.
- Provisions for units that infrequently burn oil, based on the proposed limited-use subcategory for infrequently operated oil-fired units, as well as the exemption for units that burn oil less than 10 percent of the time under the definition of fossil fuel-fired unit.[68]
- Work practice standards for dioxins/furan. EPA chose not to specify emissions limits for these pollutants, but simply required units to employ good combustion practices.
- Alternative performance standards that reduce monitoring requirements for some types of technologies.
- The use of surrogates for certain hazardous air pollutants.
- A 30 day averaging period in demonstrating compliance with the standards for coal-fired power plants.

For the proposed Utility Air Toxics Rule, EPA's discretion on the timing of implementation is limited by the explicit text in Section 112 of the Clean Air Act, which requires that sources come into compliance within three years of the promulgation of the rule.[69] This results in an expected deadline of January 2015. However, Section 112 also allows the permitting authority to extend this compliance deadline by one year, if companies demonstrate that, despite good faith efforts, more time is needed to install pollution controls.[70,71] In its March 15, 2011 proposal, EPA indicated a willingness to apply this extension in order to stagger installations for reliability or constructability purposes or for other site-specific construction issues, permitting, or local manpower or resource challenges.[72] EPA encouraged companies to begin early discussions with the permitting authority to facilitate extensions, where warranted. EPA should encourage permitting authorities to make timely decisions and grant extensions in advance, with appropriate conditions, where warranted.

EPA also requested comment on whether such an extension could be granted to complete on-site replacement capacity, rather than install controls, at an affected facility. BPC agrees that this would be an appropriate and beneficial interpretation of the Clean Air Act waiver authority. The states or EPA, as applicable, could and should use this waiver authority to allow an extra year for those electric generating units unable to complete control installation or build on-site replacement capacity in time, particularly where reliability is a concern.

As a backstop, EPA has the ability to exercise enforcement discretion and negotiate consent decrees with regulated entities in order to allow for their continued operation. Any such consent decrees, however, should eliminate economic advantages a plant might otherwise obtain as a result of operating out of compliance. Consent decrees are negotiated once a company is deemed in violation, and stakeholders may not view this legal mechanism as an acceptable option that could be built into company planning. However, consent decrees do offer an additional means of backstop reliability protection.

Presidential Authority to Delay Utility Air Toxics Rule

As a backup to the other tools and flexibilities available to smooth the phase-in of new regulations, the President also has the ability to delay Utility Air Toxics Rule requirements for some facilities, if warranted. Although this authority has never been invoked, the President is explicitly permitted under Section 112 of the Clean Air Act to grant an additional exemption from compliance (beyond the one year extension from states) for up to two

[68] The Utility Air Toxics Rule proposes a definition of "fossil-fuel fired" for purposes of determining if an electric generating unit is subject to the rule. According to this proposal, the unit must have fired coal or oil for more than 10 percent of the annual average heat input during the last 3 calendar years or for more than 15 percent during any one of those calendar years to be subject to the Utility Air Toxics Rule.

[69] 42 U.S.C. § 7412(i)(3)(A).

[70] In most cases, the permitting authority has been devolved to states that administer their own operating permit programs under Title V of the CAA. In a few instances, such as tribal lands, EPA retains this permitting authority.

[71] 42 U.S.C. § 7412(i)(3)(B).

[72] U.S. Environmental Protection Agency. Proposed Utility Air Toxics Rule. Signed March 16, 2011. Page 443. www.epa.gov/ttn/atw/utility/pro/proposal.pdf.

In addition, EPA has proposed and should finalize compliance deadlines that provide sufficient time for planning, coordination, and installations.

years if the "technology to implement such a standard is not available" and if the exemption is found to be in the "national security interests of the United States."[73] This exemption may be renewed an unlimited number of times provided the requisite findings are made.

Presumably, the President could interpret the term "available" to encompass both technological and economic feasibility, consistent with the interpretation of that term in the context of "best available control technology" for Prevention of Significant Deterioration permitting. In addition, a threat to electric reliability could presumably serve as grounds for determining that it is in the "national security interests" of the United States to extend the Section 112 compliance deadline.

EPA Discretion on Cooling Water Rule

The Clean Water Act provides EPA with extensive discretion on the compliance timing and stringency of regulations for power plant cooling water intake. In its proposal, EPA relied on this flexibility and on cost/benefit considerations with respect to entrainment provisions to allow alternative technologies where appropriate, to accommodate site-specific constraints, and to allow sufficient time for retrofits.

EPA's March 2011 proposal requires the largest water users to conduct a study to determine whether cooling towers or alternative technologies are needed to limit damage from aquatic life being sucked into cooling water intake systems (entrainment). Study results would be considered along with other factors–such as the useful life of the facility, reliability concerns, and the benefits versus costs of installing a cooling tower–to make a site-specific determination of the "best technology available" for a particular facility. In addition, EPA's proposed cooling water rule requires facilities to meet impingement mortality limits or reduce intake velocity. In its final rulemaking, EPA should exercise its authority to allow the consideration of site-specific factors and cost-benefit analysis with respect to impingement requirements.

In addition, EPA has proposed and should finalize compliance deadlines that provide sufficient time for planning, coordination, and installations. For example, under the proposed rule, plant owners are allowed eight years to install technologies such as screens, low velocity caps, and barrier nets. The installation of cooling towers is allowed to take five to ten years in the case of existing fossil plants, or ten to fifteen years in the case of existing nuclear plants.

EPA Discretion on Coal Ash Rule

EPA also has significant flexibility to establish compliance deadlines for its proposed RCRA regulations governing the disposal of coal combustion waste, including coal ash. In its proposal, EPA took comment on whether or not coal ash should be treated as hazardous waste.[74] One option would regulate coal ash as a "special waste" under the hazardous waste Subtitle C of RCRA, whereas an alternative option would regulate the ash as non-hazardous waste under Subtitle D. The primary difference between the alternatives is that EPA retains enforcement authority under Subtitle C, whereas Subtitle D requirements would be self-implementing with no federal enforcement authority. Aside from enforcement, the actual requirements are quite similar for the two proposed options. For example, both alternatives would eventually require that surface impoundments for coal combustion waste have leachate collection and removal systems; alternatively, the impoundments would have to be closed. EPA's proposed Subtitle D regulation would require these controls to be installed by April 2017, whereas the proposed Subtitle C regulation would allow states until 2018 to implement retrofit requirements.[75,76]

However, neither RCRA subtitle requires EPA to mandate compliance by any particular deadline. Subtitle D does not require that waste storage standards be implemented in any particular timeframe. And even if EPA adopts substantially more stringent requirements under Subtitle C, Section 3004(x) of RCRA also allows EPA to modify Subtitle C requirements for coal ash sites where justified by "practical difficulties." EPA may also allow site-specific variances from Subtitle C regulations for sites with distinctive geological, climatic or chemical

[73] 42 U.S.C. § 7412(i)(4).

[74] See Hazardous and Solid Waste Management System, 75 Fed. Reg. 35,128 (June 21, 2010).

[75] This date is based on the following assumptions: 1) EPA promulgates the final CCW rule in September 2011; 2) RCRA regulations, including the coal combustion waste rule, generally take effect six months after promulgation–in this case, March 2012; 3) EPA's proposed Subtitle D regulations require retrofit within five years of the effective date of the regulation. Thus, retrofit would be required before April 2017.

[76] Under RCRA, Subtitle C regulations are subject to the same effective date provisions as Subtitle D regulations. However, most states administer RCRA requirements in lieu of EPA pursuant to a delegation of authority from the agency. In these states, certain core RCRA requirements included in new EPA regulations do not take effect until the state itself adopts a regulation reflecting the new EPA requirements–a process that RCRA usually requires to take place within one year of a new EPA regulation. Thus, the retrofit requirements under the proposed Subpart C regulations would not take effect in most states until one year later than the compliance deadline in the Subpart C regulations (April 2018).

characteristics.[77] This authority could be exercised to craft appropriate tailored deadlines for sites that are unusually difficult to retrofit, or to provide an across-the-board deferral in RCRA compliance deadlines (as EPA already proposed to do in its Subpart C regulation by changing the RCRA compliance deadline to five years from four years pursuant to its Section 3004(x) authority).

In its June 21, 2010 proposed rulemaking, EPA highlighted the environmental benefits, and lack of damages, from the beneficial reuse of coal combustion wastes in encapsulated uses such as wallboard, concrete, and bricks.[78] EPA should continue its efforts to support such beneficial reuses and finalize the Bevill exemption for encapsulated beneficial reuse of coal combustion waste.

DEPARTMENT OF ENERGY AND FEDERAL ENERGY REGULATORY COMMISSION

The Department of Energy (DOE) and the Federal Energy Regulatory Commission (FERC) have specific authorities under the Federal Power Act to ensure the stability or reliability of the transmission grid. DOE and FERC authorities can be applied to avoid potential reliability issues or emergencies in the near term and, perhaps more effectively, to support long-term planning.

Addressing Near-Term Reliability Issues

While an emergency reliability issue is unlikely and should be preventable with proper planning and oversight, DOE and FERC have authority to address such situations if they arise. Under Section 202 of the Federal Power Act, the DOE can issue emergency orders to temporarily require a unit to generate and deliver electricity. In the past, this authority has been used to address a few, short-term reliability concerns.

FERC's relevant authority stems from its mission to ensure just and reasonable rates. FERC has authority to review the rates, terms, and conditions of "reliability-must-run" (RMR) contracts between a regional transmission organization or independent system operator (RTO/ISO) and a unit intended for retirement. These types of contracts are used in RTO/ISO markets when an RTO/ISO determines that a unit proposed for retirement is necessary to ensure system reliability. In such cases, the RTO/ISO can propose or enter into a RMR agreement to compensate the generator for continued operation based on cost-of-service rates or other rate agreements.[79] Through a number of recent rate reviews, FERC has indicated that RMR contracts should be considered a solution of last resort to maintain reliability.[80]

Both DOE's emergency orders and FERC-approved RMR contracts allow generators needed for reliability to be compensated for above-market costs of continued operation. If keeping such units online requires significant capital investments in pollution controls, the associated cost-of-service may be quite high. This would be the case, for example, if a unit were kept online at cost-of-service rates, retrofitted with pollution controls, and then retired well before the capital investment could be repaid. The generator might seek to amortize the relatively high costs of the retrofit investments over a short period (e.g., the term of the RMR contract or the DOE order) at the expense of ratepayers.

Alternatively, an RMR unit might operate for a period without pollution controls. This could be a lower cost solution, although the rate tariff could still provide for above-market payments. However, operation without compliant controls would violate emissions limits, as FERC's RMR authority does not supersede Clean Air Act requirements. As discussed below, such a situation would require coordination with EPA and enforcement discretion, such as the negotiation of a consent decree to continue operating for a period without controls.

FERC reviews RTO tariff provisions relating to RMR contracts under its general rate review authority (Sections 205 and 206 of the Federal Power Act), which requires that the rates, terms and conditions for provision of jurisdictional transmission service and wholesale sales must be just and reasonable and not unduly discriminatory or preferential. In some instances where FERC has found that an RTO/ISO violated its tariff provisions, FERC has intervened in RMR determinations (an example involving ISO New England and Dominion power company is discussed in the text box).

Long-Term Planning

DOE and FERC both have broad authorities to gather information and require public utilities to file reports. In addition, DOE has specific authority under Section 202 to require utilities to report on anticipated shortages of electricity or capacity, as well as on their plans to manage

[77] 42 U.S.C. § 6924(x).

[78] FR Vol 75, No 118 June 21, 2010. Coal combustion waste proposed rulemaking.

[79] In several organized markets, including Midwest ISO and California ISO, contractual or tariff requirements obligate the generator to negotiate RMR contracts to remain in operation if the RTO/ISO concludes that continued operation of the unit is necessary for reliability. In other markets, including PJM and ISO New England, the generator's decision to accept an RMR contract is voluntary.

[80] Devon Power, LLC, 103 FERC ¶ 61,082 (2003).

shortages. In addition, FERC has broad authority to conduct investigations, including subpoenaing witnesses and requiring companies to produce relevant materials.

Expanded Role for FERC

In the future, FERC could play an expanded role in monitoring RTO forward capacity markets. State PUCs have little authority to manage resource planning and generation adequacy in restructured states, where regulated utilities do not own generation resources but rather purchase electricity from wholesale markets under relatively short-term contracts. In lieu of resource planning, several RTOs have established forward capacity markets to attract new generation capacity and provide a price signal for economic retrofits of existing capacity. However, there is some concern that these markets may not provide sufficient price signals to ensure an adequate response to significant retirements of coal-fired capacity.

Thus, FERC could undertake an effort to consider: (1) whether some or all of the RTOs face resource adequacy

FERC Oversight of RMR Contracts: ISO-NE and Salem Harbor

Using its authority under the Federal Power Act, FERC recently intervened in an ISO-New England proceeding related to a reliability-must-run type contract for Dominion's Salem Harbor 3 and 4 coal-fired generating units. In December 2010, FERC's review of ISO-NE's fourth Forward Capacity Auction determined that ISO-NE had violated its tariff provisions in failing to identify alternatives to the reliability need for Salem Harbor.[81]

Available surplus capacity contributed to several existing power plants and demand resources—a combined 1.2 GWs of capacity—opting out of the fourth ISO-NE forward capacity market auction by submitting de-list bids. However, ISO-NE determined that Dominion's Salem Harbor Units 3 and 4, in addition to Entergy's Vermont Yankee Station, could not withdraw from the market due to reliability concerns that would violate NERC, Northeast Power Coordinating Council (NPCC), and ISO-NE standards.

When ISO-NE rejects a de-list bid, their Forward Capacity Auction rules require them to look for ways to allow the generating unit to withdraw under an established timeline or, if no alternatives are available, provide compensation to retain the resource in a reliability-must-run type agreement. ISO-NE's Tariff requires that this process to identify alternatives must occur in advance of the new capacity qualification period for the subsequent Forward Capacity Auction.

Following ISO-NE's rejection of Salem Harbor's de-list bid, the Conservation Law Foundation (CLF) filed a protest which stated that ISO-NE failed to meet these procedural requirements and that this would result in unjust and unreasonable rates. ISO-NE responded by providing evidence that it repeatedly presented the specific reliability need for the Salem Harbor Units to the NEPOOL Stakeholders, including the Reliability Committee. ISO-NE also stated that because Dominion submitted a static de-list bid rather than a permanent de-list bid, Dominion did not indicate a permanent exit from the market that would trigger the need for a transmission solution. Resources that wish to withdraw from the market for a one-year period can submit either a static or a dynamic de-list bid. A permanent de-list bid withdraws the resource from all future auctions.

In December 2010, FERC concluded that ISO-NE's presentations did not satisfy the Tariff's procedural requirements. FERC ordered ISO-NE to submit a compliance filing within 60 days that either identifies alternatives to resolve the reliability need and the time to implement those solutions, or include an expedited timeline for identifying and implementing alternatives. According to CLF, such alternatives could include "energy efficiency, conservation, electric transmission line upgrades, and renewable energy."[82]

In October 2010, Dominion submitted a permanent de-list bid for Salem Harbor.

[81] ISO New England, Inc., 133 FERC ¶ 61,230

[82] Conservation Law Foundation Press Release. Federal Energy Regulatory Commission Orders ISO-NE to Plan for Close of Salem Harbor Station. December 17, 2010.

concerns driven by EPA regulations; (2) whether capacity markets are a useful tool for assuring resource adequacy in markets facing such problems; and (3) whether Section 206 of the Federal Power Act should require the reform of existing capacity markets, or the establishment of capacity markets in RTOs where they do not now exist. In essence, the FERC review would consider how capacity markets in the organized markets could and should be used to address the issue of plant retirements. FERC could undertake such a review on an RTO-specific basis or on a generic basis covering all RTOs. FERC could act to amend current RTO tariffs to provide for capacity market reforms under Section 206 of the Federal Power Act, and could take such action in RTO-specific orders or in a generic notice and comment rulemaking. Although such actions may require more time than is available for dealing with reliability issues that arise in the 2015 Air Toxics Rule timeframe, they could potentially bolster the system to address future situations.

Supporting Alternative Capacity Resources

FERC is also involved in efforts to encourage the participation of alternative resources in wholesale energy markets administered by RTOs or ISOs. On March 15, 2011, FERC issued a Final Rule that attempts to level the playing field for alternatives to traditional generation by requiring competitive rates for demand response resources.

The term "demand response" generally refers to load management programs in which electricity customers volunteer to reduce their electricity consumption during periods of peak demand in exchange for lower rates. These programs can reduce costs for all consumers because electricity is more expensive during periods of peak demand, when higher cost generators that seldom operate are required to start-up. FERC's rule requires that cost-effective dispatch of demand response resources, as determined by a new "net benefits" test, must be compensated at the locational marginal price (LMP). To comply with the rule, each RTO and ISO must file a net benefits analysis and proposed tariff revisions by July 2011.[83]

The Final Rule also requires that the cost of obtaining demand response resources must be spread among all entities that purchase energy at the times and at the locations where those demand response resources were committed or dispatched.

> Coordination between the relevant federal agencies might allow for the continued operation of coal-fired electric generating units without compliant pollution controls, if deemed necessary for reliability. Such arrangements and accommodations must be reserved for true emergency situations—they should not be relied upon as the primary mechanism for ensuring reliability during the transition.

B. INTERAGENCY COOPERATION

Although neither DOE nor FERC appear to have authority to waive environmental regulations when they issue emergency orders for a unit to continue uneconomic operation for reliability reasons, EPA might exercise enforcement discretion and negotiate consent decrees that establish the terms of such operation in the absence of compliant pollution controls. Coordination of this sort between the relevant federal agencies might allow for the continued operation of coal-fired electric generating units without compliant pollution controls, if deemed necessary for reliability. Of course, such arrangements and accommodations must be reserved for true emergency situations–they should not be relied upon as the primary mechanism for ensuring reliability during the transition to a more stringent set of environmental regulations. Further, these consent decrees should ensure that plants operating out of compliance are not economically advantaged.

C. STATE AUTHORITIES

In the United States, electricity is regulated largely at the state level and there is considerable variation in the authorities exercised and roles played by regulators from state to state. In particular, the role of state authorities is determined by the extent to which the state has retained traditional regulation of electric utilities or has restructured its wholesale generation markets (see Figure 7).[84] In regulated states, where electric utilities remain vertically integrated, state public utility commissions (PUCs) retain oversight of resource additions, retrofits, and retirements. Utilities in regulated states have the obligation to serve load reliably, and many regulated states require that integrated resource planning be conducted periodically

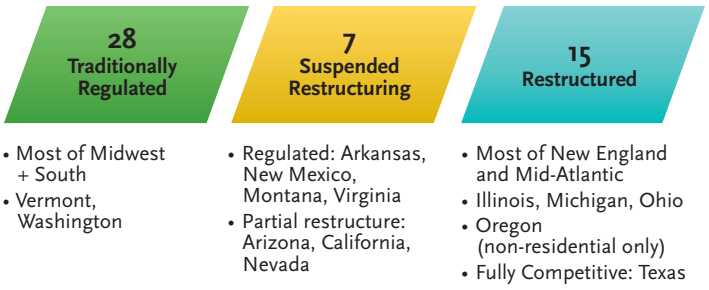
[83] This rule may be subject to additional hearings and judicial review because Commissioner Moeller dissented from the Final Rule and there is likely to be divergent stakeholder views as RTOs and ISOs adjust key analytic features for the net benefits test.

[84] Twenty eight states, including most in the Midwest and South, remain traditionally regulated even though some have undertaken restructuring studies and/or pilot programs. Seven states have suspended efforts at restructuring and are left with either partially restructured markets (e.g., Arizona, California, and Nevada) or traditionally regulated utilities. The remaining fifteen states, largely in the New England and Mid-Atlantic regions, are actively restructuring and sit on a spectrum of partially to fully de-regulated, offering retail choice and competitive rates for some or all customers. For example, Oregon offers retail choice to large commercial and industrial customers only, while areas of Texas are fully competitive with separate companies for generation, transmission and distribution, and retail sales. See http://ftp.eia.doe.gov/cneaf/electricity/page/restructuring/restructure_elect.html.

as a way to provide a built-in process for understanding and addressing future capacity needs. However, utility investments in retrofits and new capacity are subject to prudency reviews and cost recovery is not guaranteed. Uncertainty about cost recovery may cause utilities to be less proactive in making these investments.

In states that have undertaken electricity market restructuring, electric utilities have generally divested themselves of their generation resources, and may remain regulated by the state PUC only with respect to the rates they charge to retail customers. The electric utility serves load by purchasing electricity from independent producers. Because generation assets are not owned by regulated utilities, the state PUCs retain little, if any, direct authority over resource investments or operating decisions. In restructured markets, grid operators–that is, RTOs and ISOs–play an important role in fostering market conditions that encourage new investment in capacity, demand side management (DSM), or transmission when issues of resource adequacy arise.

FIGURE 7: STATUS OF STATE ELECTRICITY REGULATION/RESTRUCTURING



Source: U.S. Energy Information Administration.

In regulated states, the integrated resource planning (IRP) process informs state utility regulators who approve rate plans. State regulators should consider a forward-looking, multi-pollutant approach for planning and rate recovery decisions and require utilities to submit multi-pollutant compliance plans that include planning for forthcoming air, water, and waste rules. State regulators can encourage utilities to minimize cost by denying automatic cost recovery if, for example, a utility proposes to retrofit an aging plant that faces an uncertain future and is unlikely to remain competitive as future requirements are phased in. State utility commissions could also facilitate a smooth transition by making timely decisions on rate approvals, as well as proposed retirements and new capacity additions, so that utilities can begin construction as soon as possible, where appropriate.

Further, several states have passed laws that require utilities to plan for the installation of air pollution controls to protect public health. For example, North Carolina, Illinois, New Hampshire, Delaware, Maryland, and Massachusetts all adopted state laws prior to EPA's Transport Rule and Utility Air Toxics Rule that require multi-pollutant reductions. As a result, power companies in these states are in a good position for timely compliance with a new round of air quality regulations under the federal Clean Air Act.[85] The text box on page 35 describes Colorado's Clean Air-Clean Jobs Act, which encourages comprehensive, multi-year compliance planning.

State utility regulations also have an important role to play in integrating non-conventional capacity resources, such as demand-side resources, into planning for a reliable bulk electricity system. Incentives and fair rate policies for demand resources, distributed generation, and energy storage create a level playing field and provide meaningful incentives for new resources that could help the electricity system deliver reliable power and minimize consumer costs. Many states have enacted renewable portfolio standards and energy efficiency programs to spur the deployment of these non-conventional capacity resources.

To the extent that new environmental regulations prompt a shift to natural gas generation, either through the utilization of existing capacity or through the construction of new capacity, state PUCs could encourage long-term contracts for natural gas supply and the use of hedging instruments to manage the risk of gas price volatility. A report recently issued by the BPC's *Task Force on Ensuring Stable Natural Gas Markets* addresses this issue as one part of its comprehensive recommendations for bolstering consumer, policy-maker and investor confidence in the stability of future gas markets and for improving the tools available for effective price risk management.[86]

[85] For example, North Carolina's 2002 Clean Smokestacks Act requires coal-fired power plants to reduce NO_x emissions by 77 percent by 2009 and SO_2 emissions by 73 percent by 2013. The Illinois Multi-Pollutant Standard (MPS) and Combined Pollutant Standard (CPS) allow utilities flexibility in complying with state mercury standards in exchange for commitments to also significantly reduce SO_2 and NO_x emissions. New Hampshire's 2002 Clean Power Act requires emission reductions from the state's three largest coal-fired plants: 75 percent in SO_2 by 2006 and 70 percent in NO_x by 2006. Massachusetts regulation requires the six largest facilities to meet output-based emission standards for SO_2, NO_x, and CO_2. Maryland's 2007 Healthy Air Act requires larger reductions in NO_x, SO_2, and mercury in a shorter timeframe than previous federal rules.

[86] Bipartisan Policy Center and American Clean Skies Foundation. Task Force on Ensuring Stable Natural Gas Markets. March 2011.

STATE ENVIRONMENTAL AGENCIES

As the permitting authority under the Clean Air Act, states generally have authority to grant a one-year waiver that extends the Utility Air Toxics Rule compliance deadline for electric generating units that need more time to install pollution controls. With this one-year extension, compliance would not be required until four years after promulgating the final Utility Air Toxics Rule. States, which have typically been lenient in granting this extra year, should draw on this authority as needed to allay reliability concerns. EPA has encouraged the use of this one-year extension in its proposed Utility Air Toxics Rule.

In addition to allowing retrofits to be scheduled past the compliance deadline, states should look for ways to encourage retrofits to be scheduled well before the deadline. This would help avoid a pile-up of control installations in the maintenance season or year prior to the deadline. Specifically, states should aim to reward plants that start pollution retrofit projects as soon as possible and are able to install *and operate* their pollution controls in advance of the compliance deadline. Such early action would not only provide early emission reductions, it would take pressure off the grid during the heaviest period of pollution retrofits, when new infrastructure is also coming online to take up the slack from retired plants. Early decisions made by states to grant extensions should require plants to submit a detailed schedule for installation of pollution controls and specify consequences in the event interim deadlines are not achieved.

D. REGIONAL ORGANIZATIONS

REGIONAL TRANSMISSION ORGANIZATIONS/ INDEPENDENT SYSTEM OPERATORS

In restructured states, regional wholesale markets provide greater transparency about anticipated supply changes (including planned retirements) and create a financial incentive for timely investment in new transmission, generation, and non-conventional capacity. In these states, RTOs and ISOs typically facilitate orderly planning of power plant retirements by requiring advance notice of the intent to retire a unit and by conducting reliability impact studies. More advance notice could be helpful in identifying potential issues and allowing more time for their resolution.

RTOs and ISOs administer day-ahead and real-time electricity markets, manage transmission, and play an important role in assessing resource adequacy and ensuring operational reliability. These organizations emerged in response to FERC orders 888 and 889, which were both issued in 1996 and were intended to remove

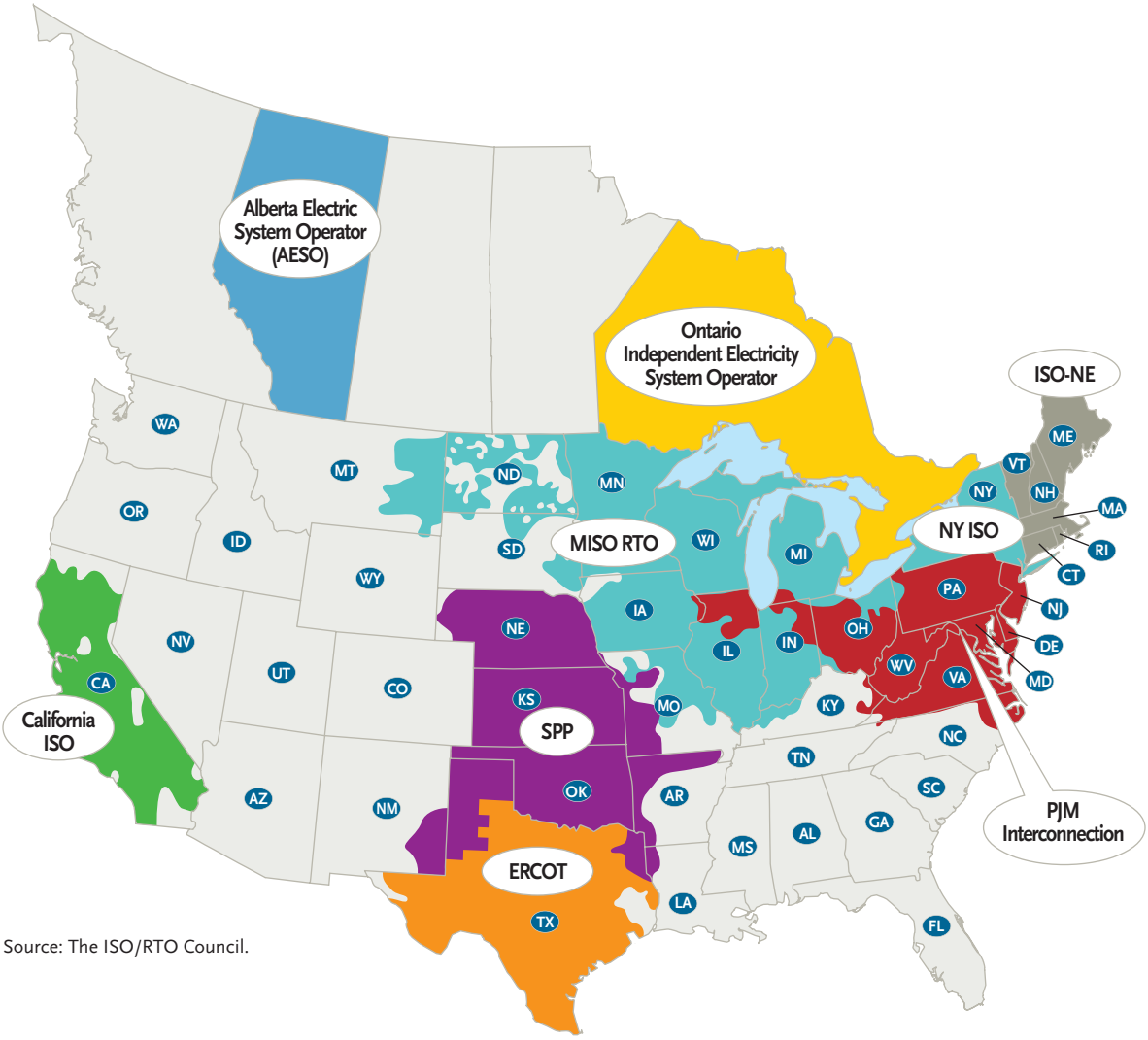
Case Study: Colorado's Clean Air–Clean Jobs Act

Colorado's Clean Air–Clean Jobs Act, signed into law by Governor Bill Ritter on April 19, 2010, is an example of state action to encourage comprehensive, multi-year planning for compliance with environmental regulation. In anticipation of a number of challenges facing the state's coal-fired utilities, the Clean Air–Clean Jobs Act directs the state's regulated utilities to work with state agencies to create proactive and comprehensive emission reduction plans.

A main driver for the legislation was that the Denver metropolitan area was in non-compliance with several air quality requirements and faced the threat of EPA-mandated compliance beginning in 2011. Therefore, the Colorado law requires each regulated utility to develop a multi-year plan to reduce NO_x emissions by more than 70 percent by 2018. The legislation also allows integrated planning for compliance with a full range of known and anticipated environmental regulations, including federal requirements under the Clean Air Act, rather than planning for one standard at a time and risking stranded assets. Each utility's plan is reviewed, by the Colorado Department of Public Health and Environment for its attainment of emissions standards and by the Public Utilities Commission in terms of projected impacts on consumers.

The Act's stated goal is to reduce costs to consumers by removing legislative and regulatory barriers to proactive, comprehensive planning. Utilities are encouraged to employ a range of methods to achieve emission reductions, but are given incentives to consider replacing coal-fired generation with natural gas-fired generation or other low-emission sources. Once its emission reduction plan is approved, the utility is given broad assurances for full recovery of costs to execute the plan. The law also provides flexibility for utilities to enter into long-term natural gas contracts to manage costs for plants that are refueled from coal to gas.

FIGURE 8. MAP OF RTOS/ISOS IN THE U.S.



Source: The ISO/RTO Council.

barriers to competitive wholesale markets by requiring open access to transmission lines. In some regions FERC approved the development of ISOs as a means of facilitating the transition to competitive wholesale markets. In 1999, FERC issued Order No. 2000, which encouraged the development of RTOs, and established criteria for them. While their activities vary somewhat by region, RTOs and ISOs serve similar functions: namely, they develop rules to govern power market and transmission market operations and operate and oversee regional wholesale markets, including coordinating the delivery of generation and transmission services.

As part of their market operations, RTOs and ISOs analyze generation and transmission resource adequacy, undertake transmission planning, review plant notices of intent to retire, and coordinate outage schedules. As noted earlier, when a generator proposes to retire a unit, the RTO/ISO assesses the reliability impact. If the RTO/ISO determines that the unit is necessary to ensure system reliability, the RTO/ISO can enter into a reliability-must-run (RMR) agreement to compensate the generator for continued operation based on cost-of-service rates.[87]

Advance notice of retirement can allow sufficient time for new resources to join the market, reducing the need to rely on RMR contracts as an interim measure to assure grid security, and mitigating the stress of assuring grid reliability in the face of retirements and retrofits. Different RTOs have different requirements with respect to the amount of notice generators must give for a proposed unit retirement. For example, PJM requires 90-day notice; NYISO requires 90 days for smaller plants and 180 days for units that are 80 MW or larger; while

[87] In several organized markets, including Midwest ISO and California ISO, contractual or tariff requirements obligate the generator to negotiate RMR contracts to remain in operation if the RTO/ISO concludes that continued operation of the unit is necessary for reliability. In other markets, including PJM and ISO New England, the generator's decision to accept an RMR contract is voluntary.

[88] PJM. Open Access Transmission Tariff. §§ 113.1-.2. September 17, 2010. Available at http://pjm.com/documents/agreements/~/media/documents/agreements/tariff.ashx.

the Midwest ISO (MISO) requires a longer, 26-week notice.[88,89,90] These advance notification requirements can be revised by RTOs/ISOs or FERC under existing RTO/ISO tariffs through a demonstration that the existing notice period is unjust or unreasonable, or unduly discriminatory or preferential. In other words, RTOs and ISOs can consider extending the notification requirement as a way to improve regional planning and reduce reliance on RMR agreements.

Some RTOs have established forward capacity markets as a mechanism to encourage the capacity investments needed to ensure continued reliability over time. In the mid-Atlantic region and New England, for example, the two ISOs–PJM and ISO New England, respectively–have well-developed forward capacity markets that allow existing and new generation resources, as well as demand-side measures, to compete alongside each other to serve future demand. As unit retirements are scheduled, the price in forward capacity market auctions increases, encouraging the development of new resources. However, the continued use of RMR contracts in both regions has led some to question whether forward capacity markets are sufficiently effective.[91]

E. COORDINATION OF FEDERAL, STATE, AND REGIONAL AUTHORITIES

The overlapping jurisdictions of environmental and electricity regulators have prompted efforts to ensure that there is coordination on reliability issues. This section discusses several examples of recent efforts to initiate or improve this coordination.

For example, DOE's Electricity Advisory Committee has issued recommendations to the Secretary of Energy for addressing power reliability concerns related to pending environmental regulations for electric generating stations.[92] The Committee advised DOE to coordinate with FERC, NERC, EPA, and state regulatory authorities to address these concerns. The Committee also put forward two specific recommendations: first, that DOE, EPA, and FERC engage in a senior-level consultative process to commit to open and active communication on reliability issues, while recognizing the existing authorities of each agency; second, that DOE advance a recommendation to FERC to improve the planning process for replacing retiring units. The latter recommendation suggests that DOE and FERC support power system "planning coordinators" who would undertake proactive planning studies, including scenario analyses, to understand the impact of retirements on the need for new generation capacity, transmission system additions, or demand-side resources. To the extent that planning coordinators can better anticipate likely retirements under different scenarios, RTOs and ISOs will have more time, information, and flexibility to take necessary action to ensure reliability.

Similarly, the Board of Directors of the National Association of Regulatory Utility Commissioners (NARUC) adopted a resolution on the role of state regulatory policies in the development of federal environmental regulations at its 2011 Winter Meeting.[93] The resolution enumerated several factors that NARUC believes EPA should consider in developing its regulations and urged state utility regulators to engage with state and federal environmental regulators. Specifically, the resolution outlined ten factors for EPA to consider, including several aimed at improving state-federal coordination and addressing reliability concerns:

- "Engage in timely and meaningful dialog with State energy regulators in pursuit of these objectives;"
- "Recognize the needs of States and regions to deploy a diverse portfolio of cost-effective supply-side and demand-side resources based on the unique circumstances of each State and region;"
- "Encourage the development of innovative, multi-pollutant solutions to emissions challenges as well as collaborative research and development efforts in conjunction with the U.S. Department of Energy;" and
- "Recognize and account for, where possible, State or regional efforts already undertaken to address environmental challenges."

[89] NYISO. Technical Bulletin 185. September 19. 2009. Available at http://www.nyiso.com/public/webdocs/documents/tech_bulletins/tb_185.pdf.

[90] MISO Open Access Transmission Tariff. §§ 38.2.7. January 6, 2009. Available at http://www.midwestmarket.org/publish/Document/1d44c3_11e1d03fcc5_-7cf90a48324a/Modules.pdf?action=download&_property=Attachment.

[91] Synapse Energy Economics, Inc. Prepared for Earthjustice. Public Policy Impacts on Transmission Planning. December 2010. In addition, FERC has found that RMR agreements weaken the incentive for new generation development by suppressing spot market prices and allowing inefficient existing units operating under RMRs to receive a higher price than new units. Devon Power LLC, et al. ER03-563-00.

[92] Electricity Advisory Committee Memorandum to Secretary Steven Chu. March 10, 2011. Recommendations to Address Power Reliability Concerns Raised as a Result of Pending Environmental Regulations for Electric Generation Stations. Available at http://www.oe.energy.gov/DocumentsandMedia/EAC_Memorandum_to_Secretary_Chu_and_Assistant_Secretary_Hoffman_3-11-11.pdf

[93] National Association of Regulatory Utility Commissioners. Resolution on the Role of State Regulatory Policies in the Development of Federal Environmental Regulations. February 16, 2011.

SECTION
V

CONCLUSIONS AND RECOMMENDATIONS

It is clear that the U.S. electric power sector is in a period of transition and that EPA regulations will influence the timing and scale of future changes in the nation's electricity supply mix. Coal-plant retirements are already occurring and are likely to continue because of market conditions such as low natural gas prices. EPA regulations, particularly the Utility Air Toxics Rule, will likely advance retirement timelines for these vulnerable plants.

The large numbers of retrofits and retirements expected to result from the EPA regulations raise significant challenges for the power sector. Nevertheless, based on the recently released proposed Utility Air Toxics Rule and 316(b) cooling water rule, it appears that EPA is making an effort to work with industry to ease the transition to a new regulatory regime. As a result, it appears that the scenarios that predicted the largest numbers of retirements will not be realized.

Moreover, even at the higher end of current estimates, the magnitude of new construction and investment would not be unprecedented, even in light of a relatively short timeframe. Between 1999 and 2004, U.S. generating capacity nationwide increased by 177 GW, almost all of which was natural gas capacity. By comparison, projected retirements between now and 2015 range from 10 to 70 GW—a much smaller change. Moreover, not all of the capacity that will be retired will need to be replaced because there is under-utilized existing generation, demand has flattened, and energy efficiency continues to improve. The industry has also demonstrated the ability to orchestrate substantial control technology retrofits. During the peak of the last retrofit construction cycle, scrubbers were installed on nearly 60 GW of coal capacity during the three-year period from 2008 through 2010.[94]

In the areas that may be most vulnerable to reliability problems, BPC believes that power companies, federal and state regulators, and ISO/RTOs have authorities or strategies at their disposal to ensure continued reliability. In light of these findings, we offer the following recommendations to ensure the smoothest possible transition to a cleaner, more efficient electric power system.

A. FLEXIBILITIES IN THE CLEAN AIR ACT AND CLEAN WATER ACT

Where appropriate, EPA should use flexibility inherent in its existing authority to address cost and reliability concerns. EPA's March 15, 2011 proposed Utility Air Toxics Rule includes several provisions that can help minimize costs and the potential for system disruptions. These include work practice standards in lieu of limits for dioxin and furans, emissions averaging among units at a facility in the same sub-category, the use of surrogates for particular hazardous air pollutants, exemptions for units that infrequently burn oil, a 30 day averaging period for demonstrating compliance with emission standards, and alternative standards that could reduce monitoring requirements. In addition, although the Clean Air Act generally allows only three years to comply with the Utility Air Toxics Rule, EPA's proposal emphasizes that states can provide waivers to allow a fourth year for facilities to install controls if plants are unable to do so in three years despite good faith efforts.

Similarly, the proposed cooling water rules provide important flexibility with respect to the timing and choice of compliance technologies. Facilities will have up to eight years to implement lower-cost compliance measures, such as screens or velocity reduction. For the largest water users, EPA's proposed rule will require a case-by-case evaluation—one that considers site-specific constraints, the useful life of the facility, electric reliability impacts, and weighs cost against benefits—to determine which control technologies, if any, will be required. If a cooling tower is required, fossil-fired facilities are provided 5–10 years and nuclear facilities are provided 10–15 years to come into compliance.

Additional options are available that can address unexpected reliability impacts as a last resort. These include authorities to delay compliance deadlines under the Federal Power Act, authorities for the President to delay implementation, and the ability to exercise enforcement discretion through the use of consent decrees to address specific, special circumstances. While it is unlikely that these authorities will be needed, government agencies should make it clear that they will avail themselves of these tools if necessary.

B. PLANNING AND COORDINATION

A number of planning tools and authorities are available and should be used to help smooth the transition to a new suite of environmental regulations in the coming decade. Although attention has focused on reliability concerns related to plant retirements, BPC believes that managing a large number of pollution control retrofits in a relatively short period could also be a challenge. If many plant owners delay retrofits to near the end of the Air Toxics compliance period, scheduling problems could arise that would increase the need for compliance waivers and reliability-must-run agreements, potentially driving up costs. Plant owners should be encouraged—including through concrete incentives, to the extent possible—to start the process of installing controls immediately. State policy makers should look for opportunities to influence the timing of retrofits and to help spread out scheduled installations within the compliance window. In addition,

[94] M.J. Bradley & Associates LLC and Analysis Group. Ensuring a Clean, Modern Electric Generating Fleet While Maintaining Electric System Reliability. August 2010.

Well-crafted legislation could provide greater certainty about environmental outcomes and provide the incentives and the regulatory clarity for utilities to begin retrofits early.

neighboring RTO/ISOs that share transmission corridors and may rely on each other to provide adequate reserve margins should consider coordinating their outage schedules as well.

To play a more proactive role, FERC could consider extending the length of the required notification period for proposed plant retirements to allow more time for reliability assessments.[95] If FERC acted to increase advance notice requirements for unit retirements, the need to rely on RMR contracts as an interim measure to assure grid security would be reduced, and the stress of assuring grid reliability in the face of retirements and retrofits may be mitigated.

Finally, DOE and FERC should look to additional authorities under the Federal Power Act that can be used to support long-term planning for a smoother, more cost-effective transition. For example, DOE and FERC could collaborate to use their information gathering authorities to conduct assessments for decision making and coordinated planning. This type of coordination could help identify regions with potential resource adequacy problems and provide a mechanism for aggregating and disseminating information about the regulatory and market tools that are available for addressing potential problems. A stakeholder process involving federal agencies, RTOs/ISOs, and utilities could be used to develop strategies for addressing challenges posed by retirement and retrofit scheduling and to share best practices.

C. SITING AND PERMITTING FOR NEW INFRASTRUCTURE

The transition to a cleaner, more efficient generation system will require investment in energy efficiency, demand response strategies, and new generation capacity along with associated transmission and pipeline infrastructure. Additional generation capacity will be needed to replace retired coal generation and, potentially to ensure reliability during retrofit outages. Energy efficiency and demand response strategies can help lower overall demand for electricity and better manage demand during peak periods. Some additional transmission infrastructure will be necessary to address shifts in generation capacity and demand, and pipelines may be necessary to transport natural gas to new gas-fired plants.

Previous BPC reports have noted that siting energy facilities in the United States has evolved into a complex, multi-jurisdictional, and often contentious process that is in need of reform.[96] Although a full discussion of potential reforms is beyond the scope of this report, it is worth noting that the upcoming period of transition in the power sector provides an opportunity for policy makers at the state and federal levels to seek improvements in the siting and permitting process.

D. LEGISLATIVE OPPORTUNITIES

There may be a short window of opportunity for a legislative change that could guarantee the environmental benefits of the Clean Air Act and provide a smoother transition for the power sector. To be successful, multi-pollutant legislation would need to provide certainty and encourage rational and timely investment decisions, so that plant owners begin adding pollution controls immediately at facilities that will remain economically viable; while also planning and coordinating the retirement and replacement of plants that will have to be shut down. For the minority of plants where the outcome is unclear, it will be important to get the information needed to make a determination in time to comply. Further, multi-pollutant legislation should aim to guarantee equivalent or greater environmental benefits than available under current authority.

Well-crafted legislation could also provide greater certainty about environmental outcomes and provide the incentives and the regulatory clarity to get started sooner. Absent new legislation, litigation over the upcoming rulemakings could prolong uncertainty over what will ultimately be required and when. In addition, the current structure provides little incentive to begin retrofits early and to turn on installed controls before the compliance deadline. Legislation could introduce such incentives and provide a backstop requirement that would be applicable if EPA is not able to promulgate regulations in time or if those regulations are tied up in litigation. This was the approach used in the successful, market-based Acid Rain Program, which is widely acknowledged to have achieved significant public health environmental benefits at lower than expected cost.

BPC continues to believe that addressing multiple pollutants in an integrated way can provide certainty, and encourage rational and timely investment decisions in pollution controls and new capacity. Several market-based, multi-pollutant legislative proposals have been developed in recent years. The BPC believes that the public health and economic benefits of these types of coordinated approaches are worth exploring in the coming months.

[95] There are currently differing requirements in PJM, MISO, NYISO.

[96] National Commission on Energy Policy. Clean Energy Technology Pathways: An Assessment of the Critical Barriers to Achieving a Low-Carbon Energy Future. March 2010.

APPENDIX A

LIST OF EXPERT SPEAKERS FROM BPC WORKSHOPS ON ENVIRONMENTAL REGULATION AND ELECTRIC SYSTEM RELIABILITY

The Bipartisan Policy Center, together with the National Association of Regulatory Utility Commissioners (NARUC) and Northeast States for Coordinated Air Use Management (NESCAUM), hosted a three-part workshop series from October 2010 through January 2011 exploring how to ensure the reliability of our nation's electric system without jeopardizing important progress on public health and environmental protection. Materials from each of these workshops, including video and presentations, can be found on our website.[97]

The three workshops featured presentations by leading experts on electric power system reliability, electricity market operation, power sector technology, and pollution control policies and regulations.

[97] See http://www.bipartisanpolicy.org.

WORKSHOP I: POWER SECTOR ENVIRONMENTAL REGULATIONS

Jason Grumet, President, Bipartisan Policy Center

Jennifer Macedonia, Senior Advisor, Bipartisan Policy Center

Daniel Greenbaum, President, The Health Effects Institute

Scott Segal, Partner, Bracewell & Guiliani

Dr. Susan Tierney, Principal, The Analysis Group

Commissioner Rick Morgan, DC Public Service Commission

Joseph Goffman, Senior Counsel to Asst. Administrator, Office of Air, US EPA

Dr. James Staudt, Principal, Andover Technology Partners

Dr. Larry Monroe, Senior Research Consultant, Southern Company

David Hawkins, Director of Climate Programs, Natural Resources Defense Council

Dave Foerter, Executive Director, Institute of Clean Air Companies

David Conover, Senior Vice President, Bipartisan Policy Center

Alex Livnat, Ph.D, US EPA Office of Resource Conservation and Recovery

Dr. Julie Hewitt, Branch Chief, US EPA Office of Water

John Novak, Ex. Director, Federal and Industry Activities, Electric Power Research Institute

Lisa Evans, Senior Administrative Counsel, Earthjustice

Joseph Stanko, Jr., Partner, Hunton and Williams

Reed Super, Attorney, Super Law Group, LLC

WORKSHOP II: RELIABILITY IMPACTS OF POWER SECTOR DEVELOPMENTS

David Conover, Senior Vice President, Bipartisan Policy Center

Tom Wilson, Senior Program Manager, Electric Power Research Institute

Howard Gruenspecht, Ph.D., Deputy Administrator, US Energy Information Administration

Joseph Chaisson, Research and Technical Director, Clean Air Task Force

Steve Fine, Vice President, ICF International

Frank Huntowski, Director, The Northbridge Group

John McManus, Vice President of Environmental Services, American Electric Power

John Shelk, President and CEO, Electric Power Supply Association

Chairman Ron Binz, Colorado Public Utilities Commission

John Moura, Technical Analyst, North American Electric Reliability Corporation

Paul Sotkiewicz, Ph.D, Chief Economist, Markets, PJM Interconnection

Ira Shavel, Vice President, Charles River Associates

Bill Tyndall, Senior Vice President, Government and Regulatory Affairs, Duke Energy

Mark Brownstein, Deputy Director, Energy Program, Environmental Defense Fund

Joe McCartin, Deputy Director, Building and Construction Trades Department

Joe Kruger, Policy Director, Bipartisan Policy Center

WORKSHOP III: LOCAL, STATE, AND REGIONAL AND FEDERAL SOLUTIONS

Jason Grumet, President, Bipartisan Policy Center

Chairman Jon Wellinghoff, Federal Energy Regulatory Commission

Vice Chairman James Gardner, Kentucky Public Service Commission

Commissioner Rick Morgan, DC Public Service Commission

Chairman Edward Finley, Jr., North Carolina Utilities Commission

Pamela Faggert, Vice President and Chief Environmental Officer, Dominion

John Hanger, former Secretary, PA Department of Environmental Protection

Sonny Popowsky, Consumer Advocate of Pennsylvania

Paul Miller, Deputy Director, NESCAUM

Sue Tierney, Managing Principal, Analysis Group, Inc

Paul Sotkiewicz, Ph.D, Chief Economist, Markets, PJM Interconnection

John Lawhorn, Sr. Director, Midwest Independent System Operator

Kathleen Barron, Vice President, Exelon Corporation

Garey Rozier, Resource Planning Manager, Southern Company

Chris James, Senior Associate, Regulatory Assistance Project

Linda Stuntz, Founding Partner, Stuntz, Davis, & Staffier, PC

Peter Tsirigotis, Division Director, US Environmental Protection Agency

Doug Smith, Member, Van Ness Feldman

Jeff Holmstead, Head of Environmental Strategies, Bracewell & Guiliani

David Hawkins, Director of Climate Programs, Natural Resources Defense Council

David Conover, Senior Vice President, Bipartisan Policy Center

Maryam Brown, Majority Staff, House Energy and Commerce Committee

Alexandra Teitz, Senior Counsel, House Energy and Commerce Committee

Michael Catanzaro, Deputy Staff Director, Senate Environment & Public Works

Jonathan Black, Professional Staff, Senate Energy and Natural Resources Committee

APPENDIX
B

BPC MODELING USING ICF'S INTEGRATING PLANNING MODEL

BPC modeled the impacts of pending EPA regulations for the power sector using ICF International's Integrated Planning Model (IPM). IPM is a model designed to simulate the behavior of the U.S. and Canadian wholesale electricity markets. To do so it uses an extensive database that contains information on every boiler and generator in the nation.

IPM is a multi-region model that endogenously determines capacity and transmission expansion plans, unit dispatch and compliance decisions, and power, coal, and allowance price forecasts, all based on power market fundamentals. To utilize the model, it is necessary to make a number of assumptions concerning key market parameters, including electricity demand growth, fuel prices, cost and performance of new generating capacity, and cost and performance of pollution controls and other options for complying with environmental regulations. This appendix discusses the assumptions and regulatory compliance scenarios included in the BPC analysis.

A. ASSUMPTIONS FOR ANALYSIS

BPC based most of the assumptions for this analysis on information from the Energy Information Administration's Annual Energy Outlook (EIA AEO 2010) and the Environmental Protection Agency's IPM Base Case 2009 ARRA (EPA ARRA). In some cases, BPC selected alternative assumptions to reflect recent market conditions. Assumptions for electricity demand growth, cost and performance of new capacity, and costs of regulatory compliance options were held constant across all the scenarios analyzed. Natural gas and coal prices varied by scenario based on the relative fuel demand from scenario to scenario. Table B-1 below summarizes the sources of key assumptions in the analysis. Tables B-2 through B-4 summarize our detailed assumptions for select parameters.

TABLE B-1: SOURCES OF KEY INPUT ASSUMPTIONS

Input Parameter	Source of Assumption	Notes
Electric demand growth	EIA AEO 2010	
Cost and performance of new generation capacity, including new project financing	EIA AEO 2010	New coal capacity without carbon capture technology included a risk premium in financing costs, consistent with the approach used by EIA
Natural gas prices	EIA AEO 2010 (BPC Base Case) Gas price sensitivity at minus $1/MMBtu below the AEO2010-based supply curve	To realize gas price response in scenarios other than the BPC Base Case, ICF derived a measure of supply elasticity from multiple AEO 2010 scenarios and applied it to the BPC Base Case price and gas demand projections to generate a supply curve
Coal prices	ICF coal supply curves calibrated to EIA AEO 2010 prices and quantities	
Cost and performance of air pollution controls	EPA ARRA (SCR, SNCR, ACI), BPC (FGD, fabric filter, DSI)	BPC assumed higher capital costs for fabric filters and wet scrubbers (FGD) than those used in EPA ARRA to reflect costs closer to recent market experience
Cost of compliance options for coal ash and water intake regulations	NERC (cooling towers), EOP Group (ash)[98] BPC (alternative water intake compliance)	

[98] Based on Utility Solid Waste Activities Group. 2010. Cost estimates for the mandatory closure of surface impoundments used for the management of coal combustion byproducts at coal-fired electric utilities. Prepared by The EOP Group, Inc., Washington, DC.

TABLE B-2: BPC ASSUMPTIONS FOR THE COST AND PERFORMANCE OF AIR POLLUTION CONTROLS

	Capacity (MW)	Wet FGD	DSI	SCR	SNCR	Fabric Filter	ACI
Capital Cost (2006$/kW)	300	564	37	168	20	131	Bit - H 3.65 Bit - L 2.72 Lig 25.11 Sub 3.86
	500	487	NA	147	15	123	
	700	442	NA	140	NA	118	
Variable O&M (2006$/MWh)		1.80	Bit 8.46 Sub & Lig 3.83	0.64	0.79	Bit - H 0.10 Bit - L 0.05 Lig 0.11 Sub 0.10	Bit - H 0.41 Bit - L 0.27 Lig 0.50 Sub 0.35
Energy Penalty		2.1%	0.02%	0.5%	0%	0.5%	0%
% Removal		SO_2 - 95%	SO_2 - 70%	NO_X - 85%	NO_X - 30%	PM - 99.95%	Hg - 90%
First Year Allowed		2013	2013	2013	2011	2011	2011
Source		BPC	BPC	EPA	EPA	EPA	EPA

Bit = Bituminous coal; Sub = Subbituminous coal; Lig = Lignite; O&M = Operating and Maintenance Costs.

Note: The 70% SO_2 removal rate for DSI assumes a fabric filter is present. As a conservative modeling assumption to account for site-specific challenges, BPC assumed that DSI was only an option for units ≤ 300MW and that units projected to install DSI are restricted to burning low sulfur coals (2 lb SO_2/MMBtu).

TABLE B-3: BPC ASSUMPTIONS FOR 316(B) WATER RULE COMPLIANCE

Water (2006$/kW)	Capacity (MW)	Cooling Tower	Alternate Compliance
Capital Costs	300	184	18
	500	138	14
	700	138	14

Note: Cooling tower costs derived from North American Electric Reliability Corporation.[99] Alternative compliance costs based on BPC assumption of 10% of cooling tower cost.

TABLE B-4: BPC ASSUMPTIONS FOR COAL COMBUSTION WASTE RULE COMPLIANCE

Ash (Million 2006$)	Fly Ash Conversion	Bottom Ash Conversion	Wet Ash Conversion	Landfill Expansion
Capital Costs	23	20	200	30
Fixed O&M	-	-	4.5	3.0

Note: Ash related costs derived from EOP Group, Inc.[100]

[99] NERC. 2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential US Environmental Regulations. October 2010. Available at http://www.nerc.com/files/EPA_Scenario_Final.pdf

[100] Based on Utility Solid Waste Activities Group. Cost estimates for the mandatory closure of surface impoundments used for the management of coal combustion byproducts at coal-fired electric utilities. Prepared by The EOP Group, Inc., Washington, DC. 2010

B. DESCRIPTION OF SCENARIOS

For this analysis, BPC defined three cases to examine the impacts of EPA's proposed regulations on the U.S. power sector. BPC had ICF analyze these cases using IPM based on the assumptions described above. The three cases included a base case, a regulatory scenario, and a regulatory scenario with lower natural gas prices. The cases are described in more detail below.

BPC BASE CASE

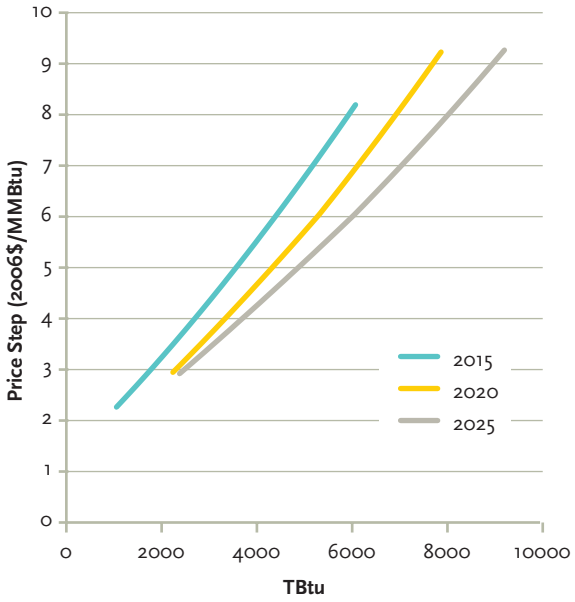
The BPC Base Case represents a business-as-usual (BAU) projection in that it includes only existing federal and state regulations. It assumes regional cap and trade programs for SO_2 and NO_X in the eastern U.S., as promulgated under Phases I and II of the Clean Air Interstate Rule (CAIR).[101] It does not include any federal mercury or carbon dioxide emission reduction requirements. The BPC Base Case includes existing state mercury, SO_2 and NO_X requirements, as well as state renewable portfolio standards. Pollution control and retirement decisions reflected in completed New Source Review consent decrees and public announcements are also included in the BPC Base Case and the other cases.

REGULATORY CASE

The second case includes requirements under EPA's proposed suite of new regulations, including the Utility Air Toxics Rule, transport, and proposed water intake and coal ash rules. BPC assumed the following requirements for each of the proposed rules:

Clean Air Transport Rule (CATR) – The case includes CAIR Phases I and II as a proxy for CATR. However, BPC assumes no banking of SO_2 allowances from the Title IV Acid Rain Program and CAIR into 2012, reflecting the start of the new program under CATR. The Phase II caps under CAIR have been modified for NO_X to reflect tighter standards expected under the new ozone NAAQS. The CAIR Phase II caps were scaled in 2018 to reflect a 0.10 lb/MMBtu standard in place of the CAIR 0.125 lb/MMBtu standard. To reflect Best Available Retrofit Technology (BART) requirements in states not subject to CAIR, units were required to control for NO_X with SCR so long as the cost of control was equivalent to less than $5000 per ton of NO_X avoided.

FIGURE B-1: BPC NATURAL GAS SUPPLY CURVES (FOR GAS SUPPLIED TO POWER SECTOR)



TBtu: Trillion British thermal units

Utility Air Toxics Rule – BPC assumes that all coal-fired electric generating units (EGUs) must be controlled with a suite of controls intended to meet emissions standards to continue operating past the 2015 compliance deadline. If units do not control by 2015, they must retire. As a conservative assumption, control of metals is assumed to require a fabric filter for every unit.[102] The analysis assumes that units greater than 300 MW meet the standard for acid gases (HCl) with a wet scrubber (flue gas desulfurization, FGD) and that units less than 300 MW in size may meet the standard for acid gases with either dry sorbent injection (DSI) combined with the fabric filter and low sulfur coal or, alternatively, with a wet scrubber.[103] Although a dry scrubber, estimated at 10-20% lower cost than a wet scrubber, would be an option in combination with particulate controls to comply with the HCl limit, it is not an assumed option in this

[101] CAIR has since been replaced with the Transport Rule, proposed in July 2010. The latter provides for more stringent caps on SO_2 and NO_X, as well as trading restrictions and limits on the use of "banked" allowances from past years of over-compliance with the SO_2 Acid Rain Trading Program. Other analyses indicate that the incremental changes between CAIR and the Transport Rule are not a significant driver in the context of the suite of EPA regulations. Thus, the policy scenario does not reflect incremental changes from CAIR, other than to restrict the use of allowances banked prior to 2012.

[102] Some studies indicate that upgrades to existing electrostatic precipitators may be sufficient to comply. (Lipinski, 2011).

[103] Studies and EPA analysis of the Air Toxics Rule indicate that lower cost dry scrubber technology combined with particulate controls would be an alternative option for acid gas compliance and that DSI may also be an option for larger units. (Lipinski, 2011)

analysis. To meet mercury standards, units may be controlled with activated carbon injection (ACI) or, for units burning bituminous coals, with a combination of wet scrubber and SCR controls.[104]

Water Intake (316(b)) – BPC assumes water intake structure compliance by 2022 (fossil) and by 2027 (nuclear), both reflected as 2025 in the modeled scenario. Facilities with a weighted average capacity factor of at least 35 percent in 2009 and flow design intake greater than 500 million gallons per day (MGD) are assumed to require cooling towers to operate past the compliance date. Facilities that do not meet those two conditions must install alternative compliance measures, estimated by BPC to cost one-tenth the cost of a cooling tower at the facility.

Ash Handling (coal combustion waste) – BPC assumes that coal-fired facilities must fully convert to dry ash handling in order to continue operating in 2015 and later. The case assumes implementation consistent with EPA's proposal under Subtitle D. Ash is not classified as hazardous and may continue to be used for beneficial purposes. For facilities that already manage some ash using dry handling systems, the retrofit costs shown above were prorated by the share of total ash managed using wet handling systems.[105]

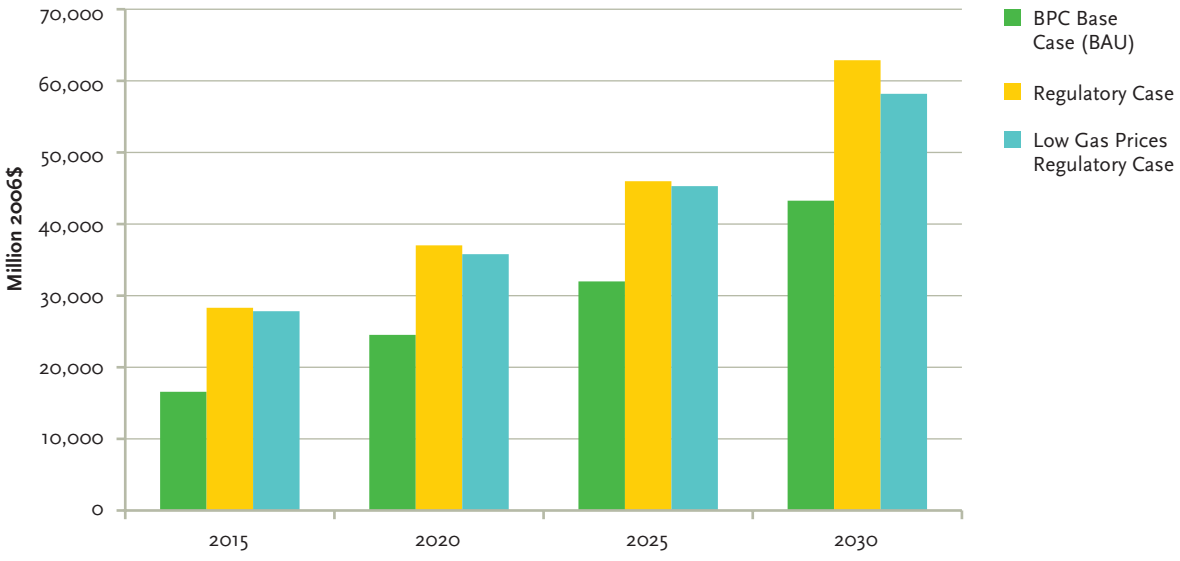
REGULATORY CASE WITH LOW GAS PRICES

Natural gas price levels are critical to determining the projected impacts of EPA's regulations on the power sector. As noted earlier, the BPC Base Case and Regulatory Case relied on natural gas price projections based on EIA's AEO 2010. Since the publication of AEO 2010 in early 2010, expert projections of future natural gas prices have continued to fall as they incorporate growing resource projections for shale gas.[106] To reflect this expectation of lower future natural gas prices, BPC includes a sensitivity case that assumes prices $1/MMBtu lower in each year compared to the projected price in the Regulatory Case.

C. SELECT RESULTS OF BPC ANALYSIS

The following charts present select results for the three BPC cases described in the previous section. Unless specified otherwise, the results are presented for the continental United States as a whole, not including Hawaii and Alaska.

FIGURE B-2: PROJECTED ANNUALIZED CAPITAL EXPENDITURES FOR REGULATORY COMPLIANCE AND NEW GENERATING CAPACITY



[104] For mercury removal, the scenario assumes that a plant burning primarily bituminous coal with installed FGD, baghouse, and selective catalytic reduction (SCR) (for NO_x) controls will meet the Utility Air Toxics Rule 90% mercury removal requirement with no carbon injection. This is a simplified estimate based on an assumption that, for a bituminous coal plant with a baghouse, any additional cost for carbon injection (polishing ACI) would be modest. All other plants are assumed to require activated carbon injection.

[105] Data on wet and dry ash handling are taken from EIA Form 923 reporting.

[106] U.S. EIA Annual Energy Outlook (AEO) 2011 projection averages nearly $1.24/MMBtu lower than the AEO 2010 projection over the period 2011 to 2030.

FIGURE B-3: PROJECTED UNIT RETIREMENTS BY TYPE

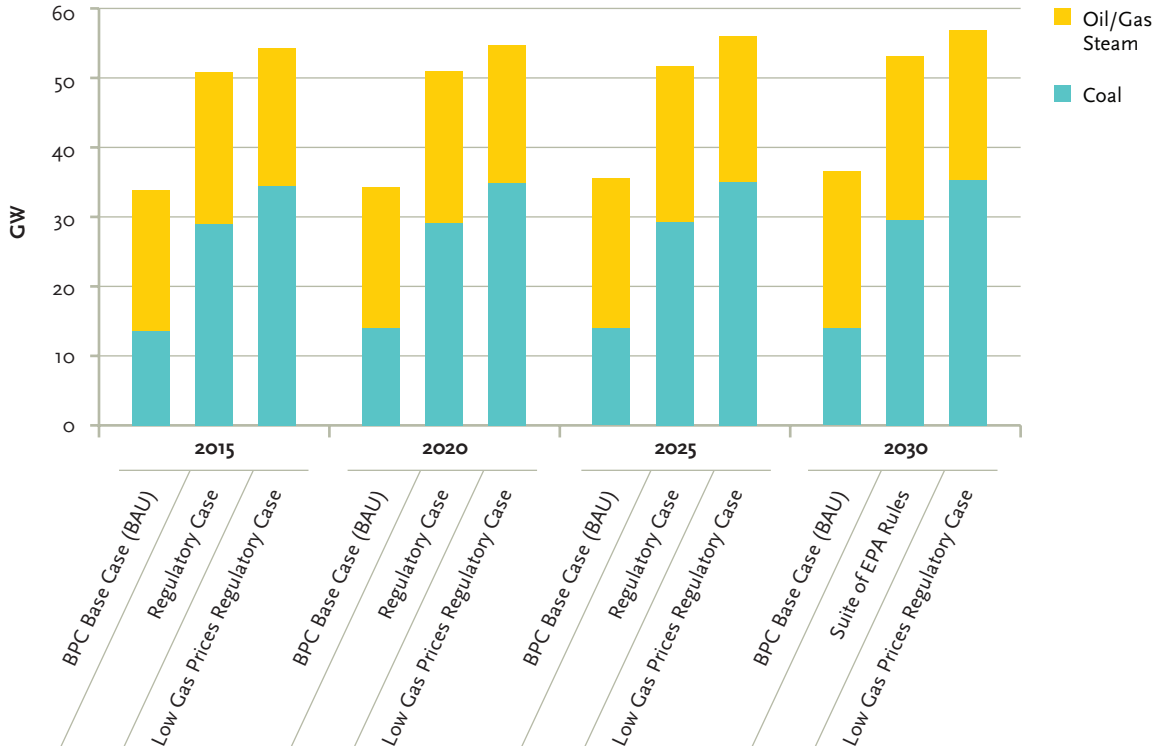


Figure B-2 shows annualized capital expenditures on all new air pollution control equipment, water intake and ash handling compliance retrofits, and new generating capacity. The 2015 value includes compliance investments for the Utility Air Toxics Rule and ash handling requirements. Water intake costs are incurred in 2025. Expenditures on new capacity take place over the entire period to meet demand growth and, in the EPA Regulatory cases, to replace capacity that retires in response to the regulations.

Capital expenditures, which do not include fuel and other costs to generate and distribute electricity, are about $10 billion higher in the Regulatory Cases compared to the BPC Base Case in 2015. The differential increases over time as costs are incurred for water intake compliance and incremental capacity additions. Costs in the Low Gas Price case are slightly lower due to lower compliance investments.

The assumed compliance requirements in the EPA Regulatory Cases drive up retirements of coal-fired capacity relative to the BPC Base Case. The regulations increase coal unit retirements by 15 GW and 21 GW in the Regulatory Case and in the Regulatory Case with Low Gas Prices, respectively, by 2030. Retirements of oil and gas steam capacity change very little from the BPC Base Case.

TABLES B-5 (A) AND (B): PROJECTED COMPLIANCE EXPENDITURES AND UNITS CONTROLLED (ADDITIONAL TO BPC BASE CASE)

TABLE B-5(A): BPC REGULATORY CASE

	2015	2020	2025	2030
Incremental Annualized Capital Expenditures (Million $): Change from BPC Base Case				
FGD	3,170	3,170	3,170	3,165
DSI	282	282	282	282
ACI	165	161	160	160
FF	3,463	3,432	3,432	3,432
SCR	525	691	703	731
Ash	2,897	2,897	2,897	2,897
Cooling Towers	0	0	1,626	1,626
Incremental Number of Units Controlled: Change from BPC Base Case				
FGD	85	85	85	84
DSI	199	199	199	199
ACI	392	385	381	381
FF	541	536	536	536
SCR	34	47	48	48
Ash (Facilities, in whole or in part)[107]	98	98	98	98
Cooling Towers (Facilities)	0	0	93	93

TABLE B-5(B): BPC REGULATORY CASE WITH LOW GAS PRICES

	2015	2020	2025	2030
Incremental Annualized Capital Expenditures (Million $): Change from BPC Base Case				
FGD	3,124	3,124	3,124	3,119
DSI	245	245	245	245
ACI	157	154	153	153
FF	3,331	3,300	3,300	3,300
SCR	411	582	587	650
Ash	2,797	2,797	2,797	2,797
Cooling Towers	0	0	1,610	1,610
Number of Units Controlled: Change from BPC Base Case				
FGD	84	84	84	83
DSI	181	181	181	181
ACI	368	360	356	356
FF	516	511	511	511
SCR	28	41	40	44
Ash (Facilities, in whole or in part)	96	96	96	96
Cooling Towers (Facilities)	0	0	92	92

[107] The BPC analysis assumes costs for compliance with the ash handling requirements for coal-fired facilities that are proportional to the current share of wet ash handling at the facility. For example, a facility that currently relies on wet handling for one-half of its total ash handling needs is assumed to incur a cost equivalent to one-half the cost of a facility that is the same size and must convert all of its handling from wet to dry methods. BPC analysis projects that 98 facilities will be affected, either in whole or in part, by the ash handling requirements in the Regulatory Case.

FIGURE B-4: PROJECTED NATURAL GAS PRICES AT HENRY HUB

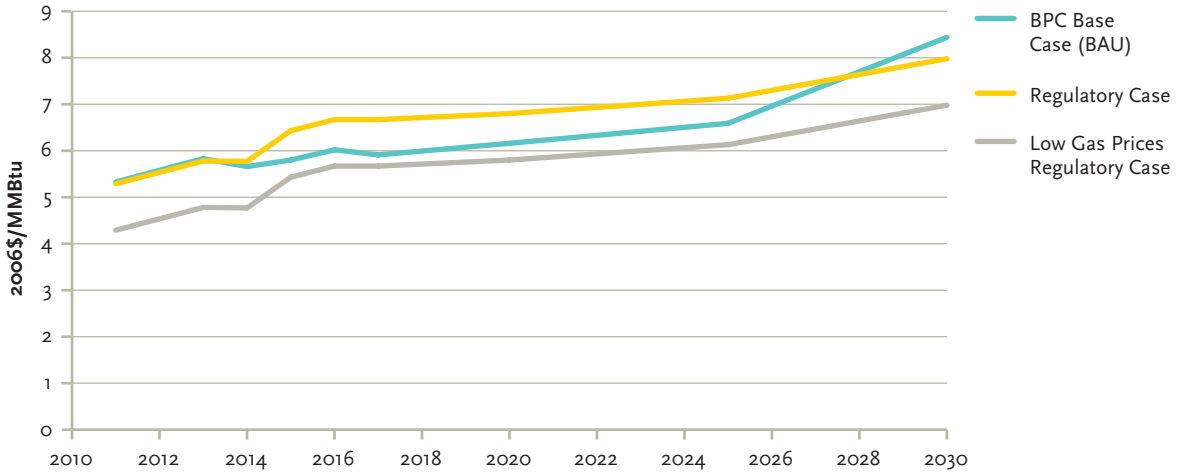


FIGURE B-5: CUMULATIVE PROJECTED CAPACITY ADDITIONS BY TYPE

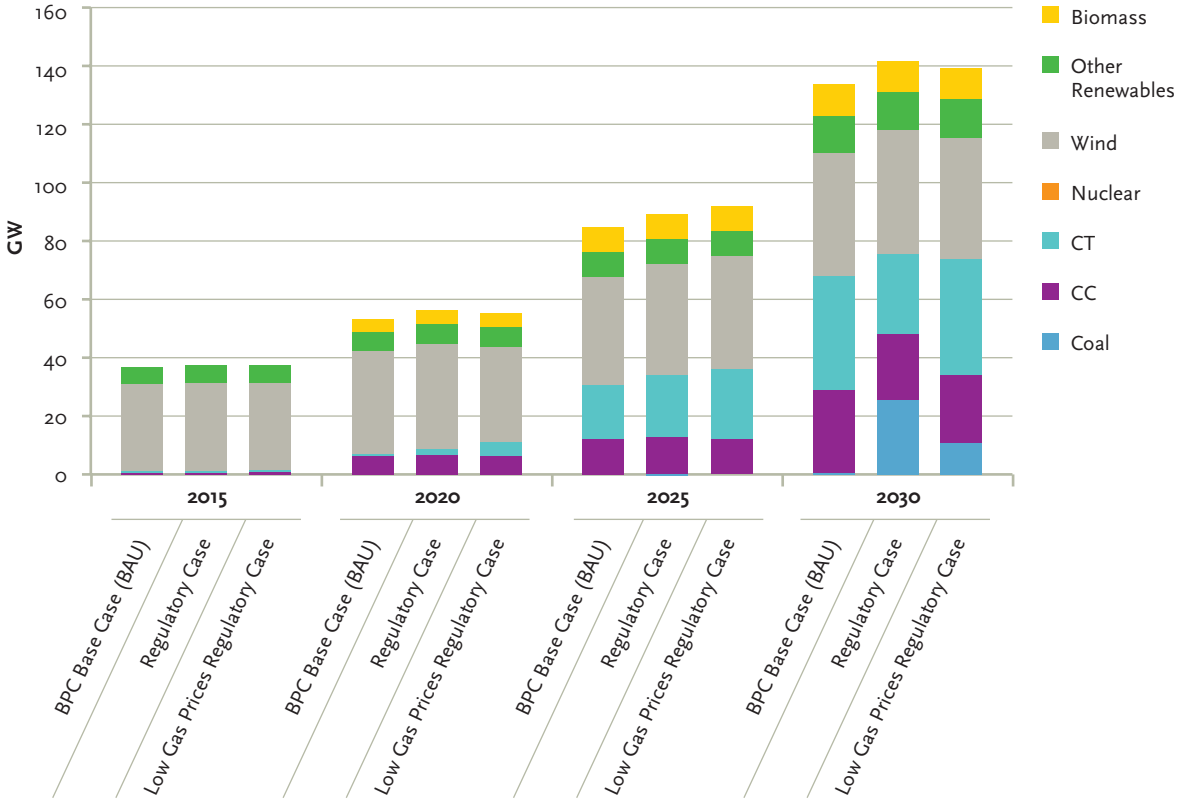


Figure B-4 shows projected natural gas prices at Henry Hub for the three cases. Prices in the BPC Base Case climb over time as demand for gas increases with electric demand growth. In the Regulatory Case, natural gas prices increase in 2015 and beyond in response to coal retirements and increased demand for gas to replace some part of that generation. As new coal capacity is brought online, gas demand and prices in the two cases approach each other and end up converging by 2030.

Figure B-5 shows cumulative U.S. capacity additions by type. In the BPC Base Case, the build mix is dominated by gas-fired capacity and renewable capacity, with the latter required to meet state RPS requirements. Higher natural gas prices in the Regulatory Case make new coal capacity an economic option, even with a financing risk premium to reflect potential carbon liabilities. Lower gas price assumptions in the Low Gas Price sensitivity case shift the economics back toward gas capacity, but some new coal capacity is also built.

FIGURE B-6: PROJECTED GENERATION MIX BY FUEL TYPE

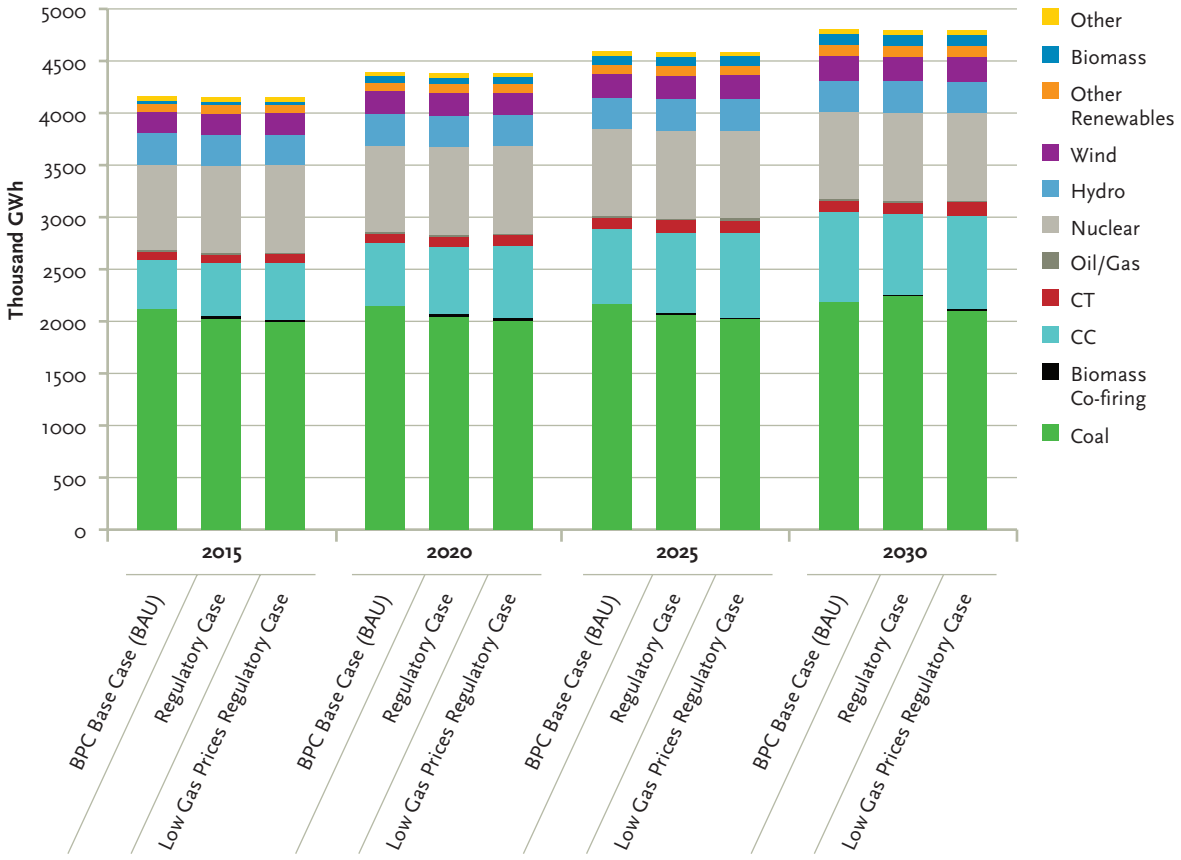


Figure B-6 shows the U.S. generation mix by type across the three cases. Generation from coal declines by 5–7 percent in the Regulatory Cases relative to the Reference Case due to retirements motivated by EPA's new regulatory requirements. Increased gas-fired generation makes up for the majority of that decline. In the Regulatory Case, generation from gas makes up roughly three-quarters of the decline in coal generation. With lower gas prices in the Low Gas Price Case, higher output from gas-fired generators makes up nearly 90 percent of the reduction from coal. In both cases, increased generation from renewables also contributes to meeting overall electricity demand growth over time.

The savings below are achieved when PC recycled fiber is used in place of virgin fiber. This project uses 1340 lbs of paper, which has a post consumer recycled percentage of 20%.

2 trees preserved for the future

7 lbs water-borne waste not created

956 gal wastewater flow saved

106 lbs solid waste not generated

208 lbs net greenhouse gases prevented

1,594,600 BTUs energy not consumed

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