RAP Energy solutions for a changing world

Preparing for EPA Regulations:

Working to Ensure Reliable and Affordable Environmental Compliance

July 2011

Electronic copies of this paper and other RAP publications can be found on our website at **www.raponline.org**.

To be added to our distribution list, please send relevant contact information to **info@raponline.org**.

Preparing for EPA Regulations:

Working to Ensure Reliable and Affordable Environmental Compliance

Author
David Farnsworth

July 2011

Contents

RAP

Introduction

This is an historical moment for public utility commissions. In the next several years, the United States Environmental Protection Agency (EPA) will be issuing far-reaching health and environmental regulations that will have significant effects on the utility sector. The ability of utility regulators to respond to this challenge is going to be tested. Traditionally, regulatory goals have included ensuring electric system reliability, promoting resource adequacy, and capturing lower energy bills for ratepayers. Now utility regulatory commissions and energy planning bodies will need to work with environmental regulators and utilities to find ways to meet these traditional goals and to achieve affordable environmental compliance at the same time.

Never before has building understanding between utility commissions and their sister regulatory agencies been so important.

Due to the extensive reach of environmental regulations, energy regulators will need to work more closely with environmental regulators as resource planning decisions are explored. Never before has building understanding between utility commissions and their sister regulatory agencies been so important. To be effective, communication among regulators can no longer be episodic; productive cooperation necessary to ensure reliable, affordable environmental compliance will require ongoing effort. By engaging with utilities and with other regulators, utility commissions will be better able to evaluate a wider array of potential compliance options, and to strike their preferred balance of cost and other policy goals, including the most affordable compliance scenarios associated with various EPA public health and environmental regulations.

Today there is an active debate over the potential effects on the nation's generation mix and electric system reliability as a result of the EPA's new and forthcoming health and environmental regulations. Recent studies reviewing potential capacity retirements from forthcoming EPA regulations affecting the industry suggest a range of possible retirements from 25-76 GW by 2020.[1] Many consider the EPA's actions as further compounding already-existing uncertainty associated with grid reliability and the nation's future energy choices. Others, including the National Association of Regulatory Utility Commissioners (NARUC), are taking the EPA's actions in stride, identifying key issues, engaging the EPA, and exploring possible next steps at regional and state levels.[2]

At its February 2011 Winter Meetings, NARUC issued a resolution[3] urging the EPA, among other things, "to ensure that, as it develops public health and environmental programs," the EPA will:

- Avoid compromising energy system reliability;
- Seek ways to minimize cost impacts to consumers;" and
- Consider cumulative economic and reliability impacts in the process of developing multiple environmental

1 "A Primer on Pending Environmental Regulations and their Potential Impacts on Electric System Reliability," February 10, 2011, Paul J. Miller, Ph.D., J.D., Deputy Director, Northeast States for Coordinated Air Use Management (Miller).

2 See, e.g., NARUC Webinars: "Rulemakings Concerning Air Quality, Cooling, and Solid Waste: Implications for Utility Regulators," September 2010 http://www.naruc.org/domestic/epa-rulemaking/default.cfm?more=1; "The States Forge Ahead: Case Studies in State Clean Energy Programs." December 2010; http://www.naruc.org/Publications/livemeeting3.wmv; "Presentations from the NARUC 122nd Annual Conference," "The Climate Syndrome: Without Congressional Action, What Do State Regulators Need to Know?" http://www.naruc.org/meetingpresentations.cfm?7; "Coal Fleet Resource Planning: How States can Analyze their Generation Fleet;" NARUC has also jointly convened several meetings on these issues with the National Association of Clean Air Regulators, NACAA and the National Association of State Energy Officials, NASEO.,"

3 "Resolution on the Role of State Regulatory Policies in the Development of Federal Environmental Regulations," February 16, 2011, http://www.naruc.org/Resolutions/Resolution%20on%20the%20Role%20of%20State%20Regulatory%20Policies%20in%20Development%20of%20Fed%20Enviro%20Regs.pdf.

rulemakings that impact the electricity sector…. [4]

NARUC further asks that the EPA "encourage the development of innovative, multi-pollutant solutions," "employ rigorous cost-benefit analyses consistent with federal law," and "provide an appropriate degree of flexibility and timeframes for compliance."[5]

Also at NARUC's winter meetings, Gina McCarthy, EPA Assistant Administrator for Air and Radiation, addressed NARUC members, thanking them for their resolution, and in turn asking NARUC members to resolve to:

- Take early action— thereby lowering costs, and ensuring better health benefits for ratepayers;
- Ask utilities to begin planning now;
- Recognize that the EPA's regulations should be an integral component of the energy sector's investment strategies;
- Review all the options, not just new generation, in considering requests for cost-recovery; and
- Coordinate generation and transmission solutions with the demand side of the equation, including energy efficiency and demand response.

These complementary resolutions underscore the need for decision makers to attain key goals: achieving the health and environmental outcomes of the EPA's regulations, respecting consumers' need for electricity at reasonable costs, and maintaining reliability — not only "resource adequacy," but also "operational reliability" or "stability," that is, the ability of the system to withstand both unanticipated disturbances and those that are anticipated, like scheduled plant outages to refuel or install environmental controls.

While utility regulators will not need to become environmental regulators, for utility regulators to meet this challenge, a general understanding of the EPA's rules will be required. Meeting this challenge will also call for up-to-date utility data, and a greater appreciation of the relationship between resource adequacy and system reliability. It will also call for a methodical review of energy system "alternatives" specific to individual states and regions. This should include not only generation alternatives across the system, but also demand and delivery alternatives as well. With that understanding, utility regulators will be better equipped to work effectively with their utilities and state environmental regulators in meeting the goals of a cleaner, reliable, and affordable electric system.

This paper provides utility regulators with an outline of initial steps for developing an in depth understanding of EPA rules and regulations. It includes a review of the EPA's proposed rules—as of May 2011 — with an eye to compliance flexibility. The paper also looks generally at utility planning, suggesting approaches that companies around the country might adopt as they take stock of their existing resources and preparedness to comply in the most effective and affordable manner with the mandates of the EPA's health and environmental regulations.

This paper initially reviews current EPA air, water, and solid waste regulatory proposals. It then shifts to the subject of utility planning, and includes a look at possible data needs, scenario development, and modeling. In light of some of the initial press coverage of EPA's proposed regulations in the fall of 2010 and associated controversy, this paper also seeks to provide a broader understanding of some relevant issues related to modeling, and some of the major findings associated with more recent modeling studies of these rules.[6] Finally, this paper sets out process recommendations for commissions to consider as they engage with companies and other regulatory agencies on these issues.

4 Id.

5 Id.

6 See, e.g., "The Unseen Carbon Agenda — The EPA wants to take away 7% of U.S. power generation," *Wall Street Journal,* October 28, 2010.

Yesterday the North American Electric Reliability Corporation, a highly regarded federal energy advisory body, released an exhaustive "special assessment" of this covert program. NERC estimates that the Environmental Protection Agency's pending electric utility regulations will subtract between 46 and 76 gigawatts of generating capacity from the U.S. grid by 2015. To put those numbers in perspective, the worst-case scenario would amount to a reduction of about 7.2% of national power generation, and almost all of it will hit coal-fired plants, the workhorse that supplies a little over half of U.S. electricity.

Id. http://online.wsj.com/article/SB10001424052702303467004575574401127641896.html; see also "EPA Rulemaking to Be Transparent," Lisa P. Jackson, EPA Administrator, November 2, 2010.

Part One

New and Forthcoming EPA Health and Environmental Regulations

Introduction

In response to legal obligations imposed by Congress and the federal courts, the EPA is in the process of promulgating a suite of public health and environmental rules that will have impact on the electric sector. The power sector is responsible for a significant share of U.S. air pollutant emissions.

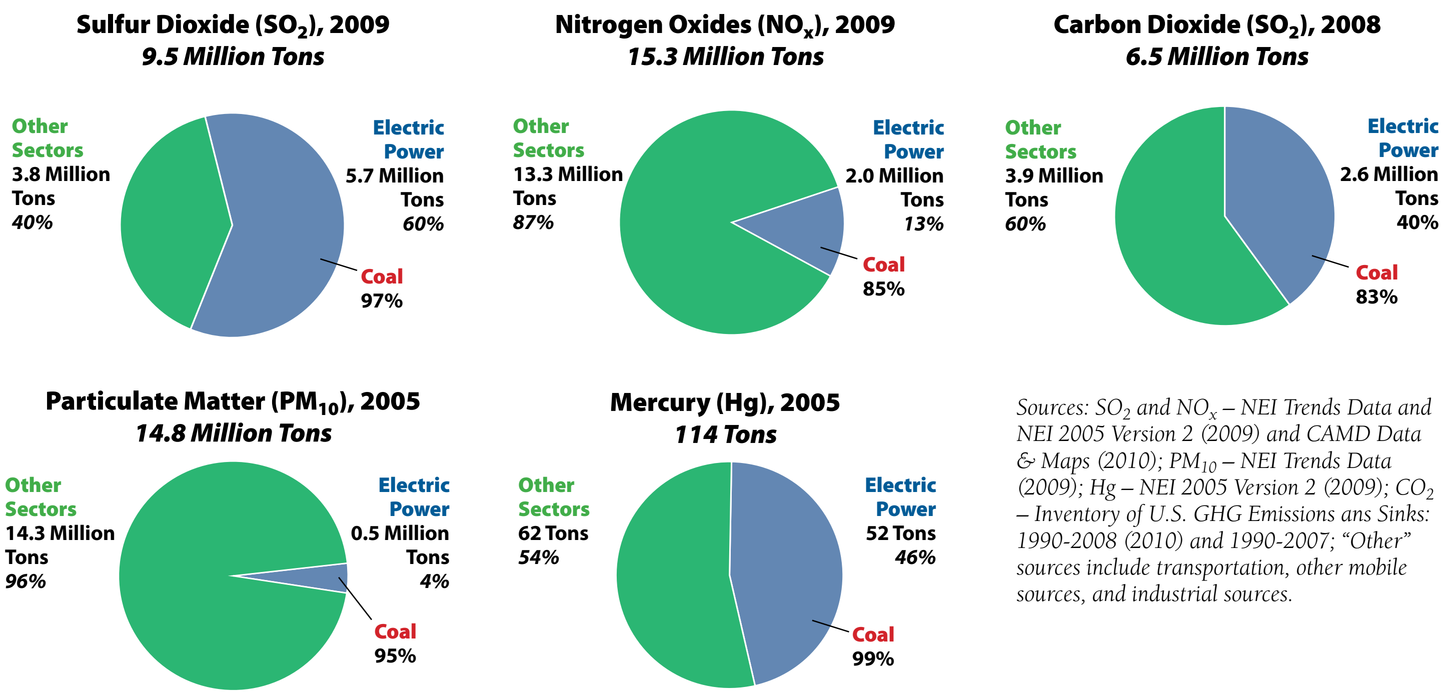
According to the EPA's Office of Air and Radiation, "power plants are among the largest U.S. emitters of air pollutants with serious health effects including premature death."[8]

While these claims may present as abstractions,

Figure 1 [7]

Power Sector: A Major Share of U.S. Air Emissions

Coal-fired power plants are the source of the vast majority of power sector air emissions



Sources: SO_2 and NO_x – NEI Trends Data and NEI 2005 Version 2 (2009) and CAMD Data & Maps (2010); PM_{10} – NEI Trends Data (2009); Hg – NEI 2005 Version 2 (2009); CO_2 – Inventory of U.S. GHG Emissions ans Sinks: 1990-2008 (2010) and 1990-2007; "Other" sources include transportation, other mobile sources, and industrial sources.

7 *Reducing Pollution from Power Plants,* Joe Bryson, U.S. EPA Office of Air and Radiation, November 16, 2010, National Association of State Utility Consumer Advocates Annual Meeting, Atlanta, Georgia.

8 Id. at 31.

9 Id.

Figure 2 [10]

Health Benefits for Millions of Americans

Benefits Greatly Exceed Costs

- EPA estimates the annual benefits from the proposed transport rule range between \$120-\$290 billion (2006 \$) in 2014 with annual compliance costs at \$2.8 billion in 2014.
- EPA estimates 2014 prices for electricity, natural gas, and coal prices increase 1 to 2%.

Estimated number of adverse health effects avoided due to implementing the proposed transport rule*

Health Effect	Number of Cases Avoided
Premature mortality	14,000 to 36,000
Non-fatal heart attacks	23,000
Hospital and emergency visits	26,000
Acute bronchitis	21,000
Upper and lower respiratory problems	440,000
Aggravated asthma	240,000
Days when people miss work or school	1,900,000
Days when people must restrict activities	11,000,000

**Impacts avoided due to improvements in PM 2.5 and ozone quality in 2014*

avoidable deaths and illnesses will continue to occur, according to the EPA, because important Clean Air Act-required power plant controls have been delayed more than a decade, leaving significant numbers of people living with unhealthy air.[11] See Figs. 3 & 4.

What follows is a discussion of newly- proposed and forthcoming EPA rules, their various attributes, goals, and implementation and compliance schedules. These descriptions are intended as illustrations. Readers should consult the latest administrative enactments, statements of agency policy, and judicial decisions for a more complete picture of the status of the rules. State environmental regulators can also serve as an invaluable resource in staying abreast of the status of these various initiatives.

Clean Air Transport Rule

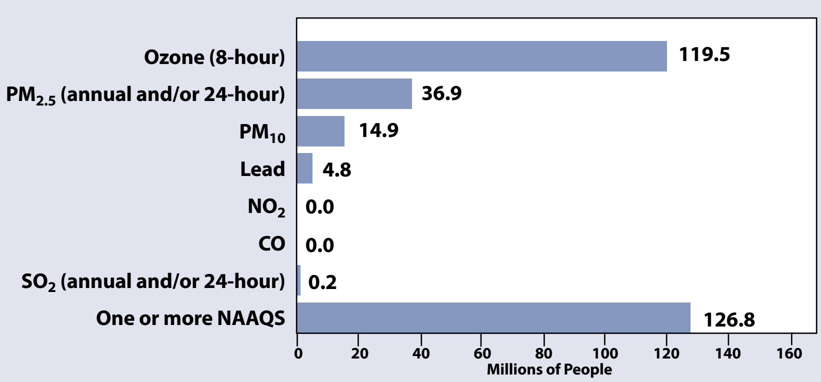
Schedule: Proposed August 2010; to be finalized June 2011

In August 2010, the EPA proposed the "Clean Air Transport Rule" (CATR).[13] CATR is a replacement for the "Clean Air Interstate Rule" that was overturned by the U.S. Court of Appeals in 2008 because it did not adequately protect downwind states.[14] CATR seeks to reduce the long-range transport of power plant emissions of sulfur dioxide (SO_2) and nitrogen oxides (NOx) that significantly contribute to the inability of downwind states to meet "National Ambient Air Quality Standards" or "NAAQS" for fine particulates (PM) and ozone. As a result of inadequate past measures,

Figure 3 [12]

Air Quality in the United States

Population living with unhealthy air quality



10 Id.

11 From Reducing Pollution from Power Plants, Joseph Goffman Senior Counsel U.S. EPA Office of Air and Radiation, October 29, 2010 (Goffman, October 2010).

12 Id.

13 75 Fed. Reg. 45210 (August 2, 2010).

14 See http://www.epa.gov/cair/. CATR will likely be further modified by outcomes associated with two other EPA rules: one, a court-ordered new standard for ozone, and the other, a new standard for fine particulate matter. The Ozone National Ambient Air Quality Standard was proposed in August 2010, Proposed Rule 75 Fed. Reg. 51,960 (August 24, 2010), http://www.epa.gov/NSR/documents/20100818fs.pdf. Pursuant to section 319 of the Clean Air Act, the EPA is seeking comments on a proposal to revise its Air Quality Index (AQI) used by states to report daily concentrations for fine particle pollution (January 15, 2009), http://www.epa.gov/pm/pdfs/20090115fr.pdf.

there is also a significant coincidence of non-attainment areas with highly populated areas. (See Figure 4) The EPA has determined that "ozone and fine particle pollution cause thousands of premature deaths and illnesses each year, and that these pollutants also reduce visibility and damage sensitive ecosystems."[15]

Focusing on states whose emissions affect their neighboring states, CATR applies to power plants in 31 states and the District of Columbia. It is scheduled to be finalized in June 2011, and compliance obligations will start within the year following.[17] The EPA sought comments on three options for structuring the emissions limits within CATR:

1. State emissions caps, with intrastate trading and limited interstate trading among power plants allowed;[18]
2. State emissions caps, with intrastate trading among power plants in a state allowed; or
3. State emissions caps with unit-specific emissions limits.

CATR compliance is envisioned in phases. For annual SO_2 and NOx, Phase I compliance is expected in January 2012, and Phase II in January 2014. For seasonal NOx (i.e., NOx emitted during the summer ozone season), Phase I compliance is expected in May 2012, and Phase II in May 2014.

CATR will require investment in controls for NOx– (typically Selective Catalytic Reduction [SCR] or Selective Non-Catalytic Reduction [SNCR]) and for SO_2 (typically flue-gas desulfurization [FGD] or "scrubbers") and dry sorbent injection (DSI).[19] A little less than half of the country's existing and "planned committed" coal steam

Figure 4[16]

Worst Air Pollution Near Population Centers

Counties violating air quality standards in the proposed transport rule region (based on 2003-07 air quality monitoring data)

Counties with violating monitors *(207)*. These counties are violating one or more of the following NAAQs: 1997 PM 2.5, 1997 Ozone, 2006 PM 2.5, and have at least one ozone and/or PM 2.5 monitor which violated the NAAQs in the periods 2003-2005, and/or 2005-2007.

15 US EPA. Air Transport Rule Information Page. June 27, 2011. http://www.epa.gov/airtransport.

16 Ensuring a Clean, Modern Electric Generating Fleet while Maintaining Electric System Reliability, M.J. Bradley & Associates and the Analysis Group, August 2010 (Maintaining Reliability), at 20, Figure 7.

17 Reducing Air Pollution from Power Plants, Joe Goffman, U.S. EPA Office Air and Radiation, September 24, 2010 (Goffman, September 2010); "Emissions reductions will begin to take effect very quickly, in 2012 — within one year after the rule is finalized." Clean Air Transport Rule Fact Sheet, http://www.epa.gov/airtransport/pdfs/FactsheetTR7-6-10.pdf.

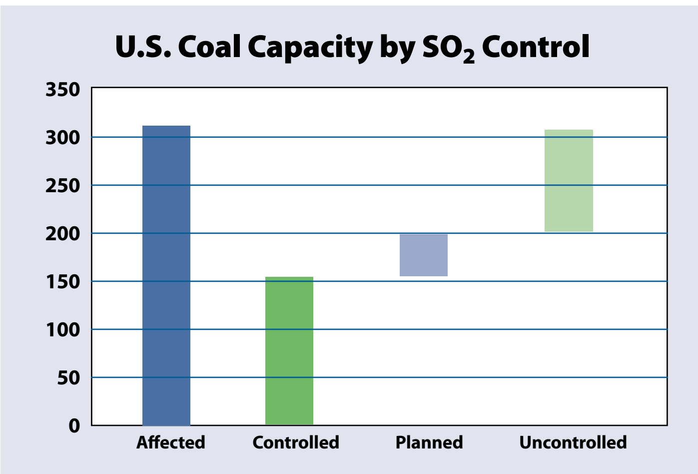
18 The EPA's preferred approach. Under this approach, SO_2 and NOx would be regulated via three cap-and-trade programs: SO_2, annual NOx, and seasonal NOx.

19 "Clean Air Act Regulation, Technologies, and Costs," Power Sector Environmental Regulations Workshop (Power Sector Workshop), David C. Foerter, Executive Director, Institute of Clean Air Companies (ICAC), October 22, 2010. According to the Clean Air Task Force, "The Toll From Coal—An Updated Assessment of Death and Disease from America's Dirtiest Energy Source" Clean Air Task Force, September 2010":
In the last five years, emissions control equipment installed at power plants around the country (flue gas desulfurization or FGD for SO_2 and selective catalytic reduction or SCR for NOx reduction) have helped coal plants achieve reductions in their emission rates of SO_2 and NOx by an average of 72 percent and 74 percent respectively.
http://www.catf.us/resources/publications/files/The_Toll_from_Coal.pdf at note 3 citing to EPA Continuous Emissions Monitoring System (CEMS) data available at http://camddataandmaps.epa.gov/gdm/index.cfm?fuseaction=emissions.wizard.

capacity has installed SCR or SNCR post-combustion NOx controls.[20]

With regard to FGD, according to ICF's May 2010 report for the Interstate Natural Gas Association of America (INGAA) entitled "Coal-fired Electric Generation Unit Retirement Analysis" (INGAA Analysis), of the approximately 310 GW of coal capacity nationwide – 150 GW already have scrubbers installed, and that an additional 50 GW have scrubbers permitted or under construction (See Figure 5).[21] ICF concluded that "about one third of the U.S. coal-fired generating capacity, or about 110 GW, will have to decide whether to install the necessary control equipment or potentially shut down."[22]

Figure 5[23]



Mercury/Air Toxics Rule

Schedule: Proposed March 16, 2011; to be finalized November 16, 2011

On March 16, 2011, the EPA proposed the first national standard to reduce mercury and other toxic air pollution from coal and oil-fired power plants as required under the Clean Air Act. The EPA termed its rule "National Emissions Standards for Hazardous Pollutants," but it is commonly referred to as the "Mercury/Air Toxics Rule."[24]

Power plants are responsible for half of the nation's mercury emissions and half of the acid gases, and the utility industry has been on notice for many years that these standards would be forthcoming.[25] The EPA estimates that there are approximately 1,350 coal- and oil-fired units at 525 power plants that would be subject to this rule. Pollutant emissions that the rule covers include mercury, arsenic, other toxic metals, acid gases, and organic air toxics such as dioxin. Human health effects of exposure to these pollutants include neurologic developmental effects (mercury), inflammation and neurotoxicity (cadmium, manganese, and lead), acute inflammation and irritation (acid gases like hydrogen chloride and hydrogen fluoride), and potential cancer risks (dioxins).[26]

20 According to the EPA, 48.93% of existing and "planned committed" "coal steam" capacity in the country has installed SCR or SNCR post-combustion NOx controls. U.S. EPA National Electric Energy Data System version 4.1 http://www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev410.html#needs. The EPA defines capacity as "net summer dependable capacity (in megawatts) of the unit available for generation for sale to the grid. Net summer dependable capacity is the maximum capacity that the unit can sustain over the summer peak demand period reduced by the capacity required for station services or auxiliary equipment." Id.

21 "Coal-fired Electric Generation Unit Retirement Analysis," INGAA, May 11, 2010. INGAA is the North American association representing interstate and interprovincial natural gas pipeline companies.

22 Id. at 1-2.

23 Id.

24 The Mercury/Air Toxics Rule is also known as the MACT rule. See 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, March 16, 2011, http://www.epa.gov/airquality/powerplanttoxics/pdfs/proposal.pdf.

25 The 1990 Clean Air Act amendments require EPA to develop an emissions control program for certain listed air toxics. Sec 112--Hazardous Air Pollutants (HAP) http://www.epa.gov/ttn/atw/utility/utilitypg.html In 2000 EPA conducted a study required by the Clean Air Act in which EPA determined that regulating mercury and other toxic emissions from power plants was "appropriate and necessary." "Regulatory Finding on the Emissions of Hazardous Air Pollutants from Electric Utility Steam Generating Units," 65 Fed. Reg. 79825 (December 20, 2000). Subject to a 2009 consent decree, EPA was obligated to propose a toxics rule and emissions standards by March 16, 2011, and to finalize the rule by November 16, 2011. EPA's 2003 decision to "delist" mercury and regulate it, instead, as "nonhazardous" under section 111 of the Clean Air Act was overturned by the D.C. Circuit in New Jersey v. EPA, 531 F.3d 896 (D.C. Cir. 2008) DC Circuit No. 05-1097. EPA appealed the ruling until, in February 2009, Administrator Jackson withdrew the appeal and indicated that EPA would proceed with HAP regulation for electric generators under Section 112. The Mercury/Air Toxics Rule replaces the vacated Clean Air Mercury Rule that was vacated by the DC Circuit in 2008. In October 2009, EPA entered into a consent decree that required EPA to propose a MACT standard for both coal and oil plants. In December 2009, EPA indicated that it will undertake an "Information Collection Request," due to statutory requirements for establishing emission standards under CAA Section 112(d) and the recent court decisions, EPA wants to acquire additional data from both coal-fired and oil-fired electric utility steam generating units." https://utilitymacticr.rti.org/FAQ/FAQEPAPolicy.aspx#EPA-001

The Standard

Section 112 of the Clean Air Act contains standards for both existing and new sources.[27] The Section 112 standard for existing sources states that Maximum Achievable Control Technology or "MACT" "shall not be less stringent, and may be more stringent than the average emission limitation achieved by the best performing 12 percent of the existing sources…in the category or subcategory…" This calculation is referred to as the "MACT floor," and does not take cost into account but does reflect what existing and deployed technology can do. The EPA can require what are referred to as "beyond-the-floor" reductions if cost-effective technologies are available. Section 112 states that "new" sources "shall not be less stringent than the emission control that is achieved in practice by the best controlled similar source, as determined by the Administrator."

The proposed Mercury/Air Toxics rule sets standards based on the best-performing 12 percent of coal- and oil-fired electric generators with a capacity of ≥25 MW for all hazardous air pollutants or "HAPs" emitted. (See Table A) The EPA has also proposed two subcategories: (1) lignite-burning, mine-mouth coal-fired boilers, and (2) solid and liquid oil units.[28]

The schedule for compliance under the Mercury/Air Toxics Rule varies for existing and new sources. Existing sources are required to meet standards within 3 years from the date of the final rule, with the opportunity for a one-year extension. Compliance for new and reconstructed sources will be required going forward on issuance of final rule.

Table A

Proposed Mercury/Air Toxics Rule Emissions Limitations[29]

Subcategory	Particulate Matter	Hydrogen Chloride	Mercury
Existing coal	0.03 lb/MMBtu	0.002 lb/MMBtu	1.2 lb/TBtu[30]
Existing coal (Lignite)	0.03 lb/MMBtu	0.002 lb/MMBtu	11lb/TBtu[31]
Existing IGCC	0.05 lb/MMBtu	0.0005 lb/MMBtu	3 lb/TBtu
Existing solid-oil derived	0.2 lb/MMBtu	0.005 lb/MMBtu	0.2 lb/TBtu
New coal	0.05 lb/MMBtu	0.3 lb/MMBtu	0.00001 lb/GWh
New coal (lignite)	0.05 lb/MMBtu	0.3 lb/MMBtu	0.04lb/GWh

Flexibility

A 2010 study by the North American Electric Reliability Corporation (NERC) stated that the "only flexibility for compliance [under this rule] is for EPA to grant a one-year extension, granted on a case-by-case basis, and a Presidential exemption of no more than two years based on

26 "Understanding the Health Effects of Power Plant Emissions," Dan Greenbaum, President, Health Effects Institute, Bipartisan Policy Center Conference on "Environmental Regulation and Electric System Reliability," October 22, 2010. http://www.bipartisanpolicy.org/events/2010/10/environmental-regulation-and-electric-system-reliability. See also, e.g., "The Toll From Coal—An Updated Assessment of Death and Disease from America's Dirtiest Energy Source." Clean Air Task Force, September 2010. This is an update of similar Clean Air Task Force studies from 2000 and 2004 that looked at health impacts caused by fine particle air pollution from the nation's roughly 500 coal-fired power plants which found that "emissions from the U.S. power sector cause tens of thousands of premature deaths each year and hundreds of thousands of heart attacks, asthma attacks, emergency room visits, hospital admissions, and lost workdays." Id. at 4. The current study develops estimates of health impacts using an established and peer-reviewed methodology approved by both the EPA's Science Advisory Board and the National Academy of Sciences. It concludes that fine particle pollution from existing coal plants were expected to cause nearly 13,200 deaths in 2010, and an estimated 9,700 hospitalizations and over 20,000 heart attacks per year. Id.

27 The EPA has proposed several subcategories of emitters for purposes of this rule: mine-mouth, lignite-burning generators, and solid and liquid oil units.

28 These are included because "even though petroleum coke is derived from oil, it is a solid fuel and cannot be burned in a liquid oil-fired boiler." "Power Plant Mercury and Air Toxics Standards, Overview of Proposed Rule and Impacts," March 16, 2011.

29 Adapted from "Implications of New EPA Regulations on the Electric Power Industry in the West," Joint Meeting of the State-Provincial Steering Committee and Committee on Regional Electric Power Cooperation, Steven Fine, ICF International, April 12, 2011 at slide 19.

30 During this rulemaking, an industry representative, the Utility Air Regulatory Group (UARG), identified an error in the manner in which the EPA had calculated the MACT floor. In a May 19, 2011 letter from the EPA to UARG, the EPA proposed to reset the mercury level from 1 lb/TBtu to 1.2lb/TBtu. http://insideepa.com/iwpfile.html?file=may2011%2Fepa2011_0964a.pdf

31 The EPA has proposed a beyond-the-floor limit of 4 lb/TBtu.

availability of technology and national security interests."[32] While Presidential exemptions have been used in limited circumstances,[33] the EPA's Mercury/Air Toxics Rule actually contains a number of significant flexibility provisions.

First, the rule allows for facility-wide averaging for all HAP emissions from existing units within the same subcategory.[34] In other words, a facility might have several similar units emitting a hazardous pollutant, mercury for example. Under the rule, emissions from similar units can be averaged across the facility, in effect treating the facility as though it were one emissions source. According to the EPA, "[e]missions averaging . . . could only be used between [electric generating units] in the same subcategory at a particular affected source." This approach will allow environmentally equivalent but less costly ways of achieving emissions standards. With the opportunity to average emissions facility-wide, the Mercury/Air Toxics Rule offers the potential for significantly less onerous compliance than would be available if the rule were imposed at a unit-by-unit level."[35]

Second, the proposed rule would allow for averaging of facility emissions to accommodate generators' operational variability. Averaging would be allowed over a thirty-day period.

Third, the proposed Mercury/Air Toxics Rule also provides for flexibility and less costly compliance demonstration methods through the use of "surrogates" (i.e., the control of one pollutant as a proxy for others).[36] This would allow an emitter to demonstrate control over the emission of a pollutant that typically accompanies another pollutant by simply demonstrating control of that other pollutant. For example, there are emissions limits for particulate matter as a surrogate for non-mercury metals. In that case, non-mercury metal emissions limits can be met through a demonstration of particulate matter controls. Similarly, hydrogen chloride is being proposed as a surrogate for other acid gases. The proposed rule also preserves the more typical approach of measuring metals or individual acid gases themselves.

Fourth, the rule creates conditions that encourage fuel switching (i.e., between types of coal), an additional flexible aspect of the rule. Although the expression "maximum available control technology" implies a technology standard, MACT is a performance-based emissions rate set with regard to the performance of existing sources and technologies being used at those sources. Unlike percent-removal standards such as those found in many state mercury laws,[37] the MACT standard results in the actual amount of removal required varying by coal type. For example, Fig. 6 shows that Texas Lignite (TL) has the highest concentration of mercury content (pounds per million BTU) of the types of coal listed. Mercury content decreases progressively in Western bituminous (WB), Illinois Basin (IB), Northern Appalachian (NAP), and Powder River Basin coal. Thus, burning Texas Lignite would require greater levels of removal than would the use of other types of coal. Conversely, other types of coal would require lower levels of removal.

A similar analysis holds true for removal of hydrochloric acid from coal. (See Fig. 7). Illinois Basin coal has greater

32 2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations (NERC Study), NERC, October 2010 at 60.

33 See Ensuring a Clean, Modern Electric Generating Fleet while Maintaining Electric System Reliability, M.J. Bradley & Associates and the Analysis Group, August 2010, Michael J. Bradley, Susan F. Tierney, Christopher E. Van Atten, Paul J. Hibbard, Amlan Saha, and Carrie Jenks (M.J. Bradley Study), sponsored by the "Clean Energy Group" (i.e., Calpine Corporation, Constellation Energy, Entergy Corporation, Exelon Corporation, NextEra Energy, National Grid, PG&E Corporation, and Public Service Enterprise Group) at 22.

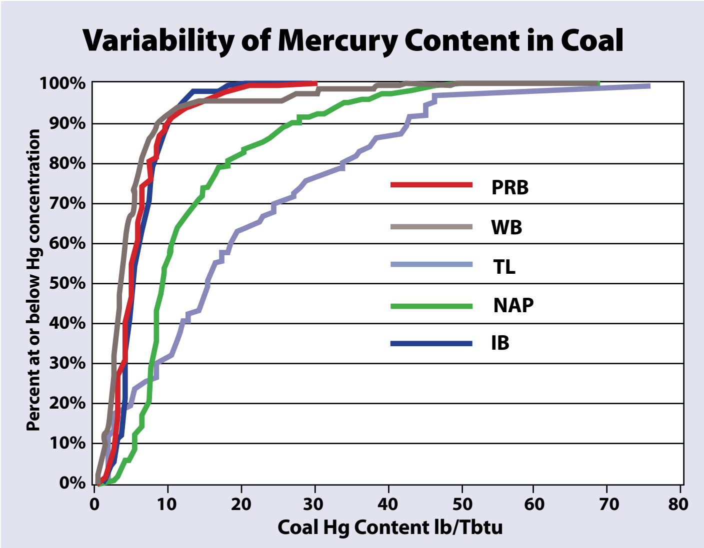
34 Note that this does mean averaging can occur across pollutants (e.g., mercury for benzene). EPA 40 CFR Parts 60 and 63 [EPA-HQ-OAR-2009-0234; EPA-HQ-OAR-2011-0044, FRL-9148-5] RIN 2060-AP52 "National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional." Id. at 431 (Proposed MACT Rule) http://insideepa.com/iwpfile.html?file=mar2011/epa2011_0509a.pdf.

35 According to the NERC Study, the "potential EPA MACT rule will apply to all 1,732 existing and future coal and oil fired capacity (415.2 GW of existing plus another 26 of new planned coal units)." The EPA estimates, however, that there are approximately 1,350 coal- and oil-fired units at 525 power plants that emit pollutants that would be subject to this rule.

36 Proposed Mercury/Air Toxics Rule at 535.

37 Over 20 states have mercury laws. See "A Patchwork Program: An Overview of State Mercury Regulations," Stephen K. Norfleet and Robert E. Barton, RMB Consulting & Research, Inc. Electric Utilities Environmental Conference Tucson, Arizona, January 21-24, 2007, http://rmb-consulting.com/papers/A%20Patchwork%20Program-An%20Overview%20of%20State%20Mercury%20Regulations.pdf.

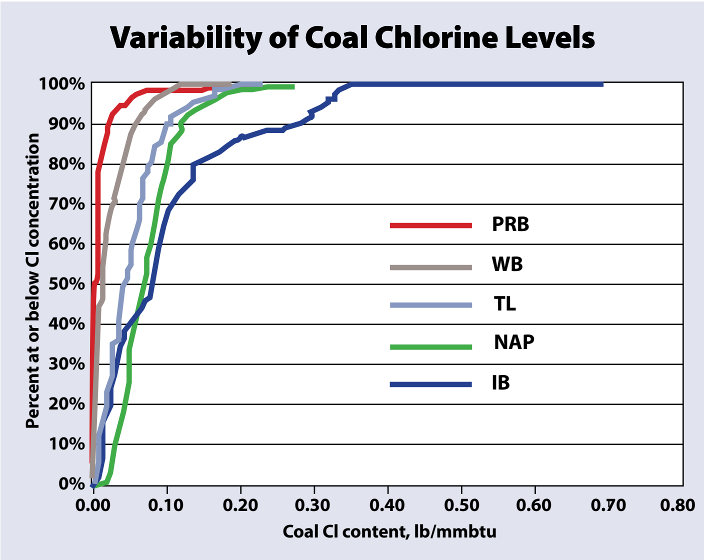
Figure 6 [38]



amounts of chlorine and will require greater levels of removal than the other types of coal shown.

Depending on the types of coal economically available,

Figure 7 [39]



the Mercury/Air Toxics Rule thus allows for the use of cleaner types of coal as part of industry compliance strategies.

Units that already have scrubbers can be expected to have less difficulty complying with the Mercury/Air Toxics Rule.[40] They are likely to be able to meet acid gas emissions requirements and, depending on coal type, may be able to meet mercury removal limits.[41] "Unscrubbed" units will need to install electrostatic precipitators (ESPs) or fabric filters for particulates, make use of alternative sorbents such as activated carbon or halogen additions for mercury,[42] and dry sorbent injection (e.g., Trona, Sodium Bicarbonate, or Hydrated Lime, also called "dry-scrubber technologies," for strong acids (hydrochloric and hydrofluoric acids).[43]

Finally, the EPA recognizes that compliance costs associated with this rule can be significantly reduced by including energy efficiency investments in compliance strategies that achieve moderate levels of energy demand reduction:

> *End-use energy efficiency can be an important part of a compliance strategy for this regulation. It can reduce the cost of compliance, lower consumer costs, reduce emissions, and help to ensure reliability of the U.S. power system. Policies to promote end-use energy efficiency are largely outside of EPA's direct control. However this rule can provide an incentive for action to promote energy efficiency.*[44]

To examine the potential impacts of federal and state energy efficiency policies, the EPA used the Integrated Planning Model (IPM). It first modeled a base case that reflected future energy prices and bills without a MACT standard. Then they modeled future prices and bills with a MACT standard (row one of Table B). Then they modeled

38 Adapted from "Surviving the Power Sector Environmental Regulations," Staudt, October 2010.

39 Id.

40 "Surviving the Power Sector Environmental Regulations," James Staudt, Ph.D., The Bipartisan Policy Center's National Commission on Energy Policy (NCEP), October 22, 2010.

41 Id.

42 Id. Activated carbon is more absorbing because it is more porous. This capacity can be enhanced by further treating carbon with a compound that reacts chemically with mercury. Halogen converts mercury to mercuric halide, and this can be absorbed by coal ash and dry flue gas desulphurization solids. Combining halogen and activated carbon also presents a lower cost approach to other sorbents such as bromated activated carbon. See "Options for High Mercury Removal at PRB-fired Units Equipped with Fabric Filters with Emphasis on Preserving Fly Ash Sales," Paradis et al. http://secure.awma.org/presentations/Mega08/presentations/6a-Dutton.pdf; see also NALCO/Mobotec, http://www.nalcomobotec.com/expertise/mercury-control.html.

43 Like other sorbents, these are injected into the furnace (i.e., upstream from the particulate removal device). They react with the acid gas and are caught by ESPs or fabric filters.

44 "Power Plant Mercury and Air Toxics Standards, Overview of Proposed Rule and Impacts," March 16, 2011 at 545.

MACT plus energy efficiency (row two of Table B).

The EPA assumed, first, that the states adopted ratepayer-funded energy efficiency programs, such as an energy efficiency resource standard. The EPA's model relied on savings estimates taken from work conducted by Lawrence Berkley National Laboratory.[45] Second, the EPA used Department of Energy estimates of "demand reductions that could be achieved from implementation of appliance efficiency standards mandated by existing statutes but not yet implemented."[46] Third, the EPA assumed that the impacts of these policies would continue through 2050.[47]

The EPA concluded that its modeled energy efficiency case would significantly reduce electricity prices and the price effects of the proposed Mercury/Air Toxics Rule. As seen in Table B, the EPA's base case modeling shows that the Mercury/Air Toxics Rule would increase retail prices "by 3.7percent, 2.6 percent and 1.9 percent in 2015, 2020 and 2030, respectively, relative to the base case."[48] If energy efficiency programs were implemented, however, the retail electricity price in 2015 would increase only 3.3 percent (i.e., lower by 0.4 percent). Prices in 2020 and 2030 would decrease by approximately 1.6 percent and 2.3 percent, respectively, relative to the EPA's base case.[49]

Table B

EPA Efficiency Modeling/ Percentage Retail Price Effect

	2015	2020	2030
Cost Effects MACT Rule	3.7%	2,6%	1.9%
Cost Effects MACT Rule with Energy Efficiency	3.3%	(1.6%)	(2.3%)

This work shows incidentally the long-term rate reducing effect of energy efficiency, all else being equal, and specifically shows how pollution control can be accomplished without adverse economic effect to consumers.

Regulations for CO_2

The EPA's regulation of greenhouse gases (GHGs) to date is largely based on four separate administrative actions and rules:

1. GHG Reporting Rule
2. Endangerment Finding/Light Duty Vehicle Rule
3. Johnson Memorandum Reconsideration
4. Tailoring Rule

The EPA, however, has also indicated that it will eventually regulate GHG emissions from power plants pursuant to its authority to develop source categories and performance standards for pollution sources under section 111 of the Clean Air Act.

Reporting Rule

In October 2009, the EPA proposed a GHG Reporting Rule that requires nearly all facilities that emit 25,000 metric tons or more per year of CO_2e[50] emissions to monitor their GHG emissions and submit detailed annual reports to the EPA starting in 2011.[51] The Final Rule was issued in October 2010, and March 2011 was the first reporting deadline.[52]

Endangerment Finding

The EPA is obligated by law to regulate CO_2 emissions pursuant to the federal Clean Air Act and consistent with the 2007 Supreme Court decision in *Massachusetts v. EPA*.[53] In response, the EPA issued its Endangerment Finding,

45 Proposed Mercury Air Toxics Rule at 545, citing to "The Shifting Landscape of Ratepayer Funded Energy Efficiency in the U.S.," Galen Barbose, et al, October 2009, Lawrence Berkeley National Laboratory, LBNL-2258E.

46 The EPA notes that "appliance standards that have been implemented are in [EPA's] base case." Id.

47 Id. See Tables 22 and 23 at 545-546.

48 Id. at 548.

49 Id.

50 CO_2e is a measure of the global warming potential of all GHGs.

51 74 Fed. Reg. 56260. Created pursuant to the FY2008 Consolidates Appropriations Act (H.R. 2764; Public Law 110-161). http://www.epa.gov/climatechange/emissions/ghgrulemaking.html.

52 See 75 Fed. Reg. 66434 (October 28, 2010).

53 In Massachusetts v. EPA the Supreme Court found that GHG emissions are "air pollutants" under the Clean Air Act. The Court required the EPA to determine whether or not emissions of GHG from new motor vehicles cause or contribute to air pollution reasonably anticipated to endanger public health or welfare, and this requires the EPA to respond to petitions for rulemaking requesting the EPA to regulate CO_2 and other GHG from motor vehicles. http://www.supremecourtsus.gov/opinions/06pdf/05-1120.pdf; Status Report on Clean Air Act GHG. Regulation for Utility Regulators, Joseph Goffman, Senior Counsel, Office of Assistant Administrator Office of Air and Radiation, U.S. EPA NARUC Webinar, October 15, 2010.

stating that, "greenhouse gases in the atmosphere endanger the public health and welfare of current and future generations."[54] This finding was made with regard to motor vehicle emissions, and the EPA subsequently issued the Light Duty Vehicle Rule.[55]

Johnson Memorandum

In April 2010, the EPA issued what is known as the Johnson Memorandum Reconsideration.[56] In this memorandum, the EPA indicated that relevant permitting requirements (i.e., Prevention of Significant Deterioration [PSD] permitting) would not apply to a newly regulated pollutant until regulatory requirements to control that pollutant take effect.[57] PSD and Title V permit requirements applying to GHGs took effect on January 2, 2011. PSD is a preconstruction permit program requiring a permit before the construction of a new source or a project at an existing source that would result in a significant emissions increase. The Title V program requires an operating permit for all "major sources" (i.e., sources above a certain threshold) that have the potential to emit pollutants above a certain level. Under the memorandum, PSD and Title V programs apply automatically.

Tailoring Rule

While the Endangerment Finding and Light Duty Vehicle Rule apply to mobile sources of GHG, and the Johnson Memorandum is a general statement of policy, the Tailoring Rule, proposed by the EPA in October 2009, applies GHG regulations under PSD and Title V to major sources.[58] The EPA recognized that the existing thresholds in the Title V and PSD programs were not realistic for GHGs.[59]

Because existing PSD and Title V thresholds for air pollutants were far too low (e.g., 50-100 tons per year of carbon dioxide equivalent [CO_2e]) to apply to GHGs (which are emitted in much greater amounts), the EPA chose to "tailor" its thresholds to recognize this in a way that would allow smaller sources to avoid being required to comply with these permitting programs. The Tailoring Rule reset the thresholds for both PSD and Title V.[60] PSD is set at 75,000 tons per year, and the major source threshold for Title V is set at 100,000 tons per year of GHGs.

The Tailoring Rule focuses GHG requirements on large new emitters (including power plants) and modifications of plants that cause at least a 75,000-ton CO_2e increase. This approach makes "70 percent of the national GHG emissions from stationary sources . . . subject to permitting requirements beginning in 2011, including the nation's largest GHG emitters (i.e., power plants, refineries, and cement production facilities)." [61] Permitting will occur on a step-by-step basis.

The first step in permitting (January 2011 through June 2011) focuses on what are referred to as "anyway sources" and "anyway modifications." These are emissions sources that would be subject to PSD "anyway" based on emissions of pollutants other than GHGs. Sources that already have a Title V permit must add GHG requirements during the next revision or renewal.

The second step (July 2011 through June 2013) applies to projects that would not otherwise trigger PSD, but increase GHG emissions by more than 75,000 tons per year CO_2e or to sources that do not already have a Title V permit but which have more than 100,000 tons per year CO_2e potential to emit.[62]

The EPA plans a third step on whether to apply the

54 Proposed April 24, 2009 (74 Fed. Reg. 18,886), Final December 15, 2009 (74 Fed. Reg. 66,496)

55 Proposed September 28, 2009 (74 Fed. Reg. 49,454); Final May 7, 2010 (75 Fed. Reg. 25,324)

56 Final April 2, 2010 (75 Fed. Reg. 17,004)

57 "EPA is refining its interpretation to establish that the PSD permitting requirements will not apply to a newly regulated pollutant until a regulatory requirement to control emissions of that pollutant 'takes effect.'" Id.

58 Proposed October 27, 2009 (74 Fed. Reg. 55,292).

59 The thresholds for Title V were 100 and 250 tons per year, and had not been set for PSD. At a 25,000 tpy CO_2e threshold, "the program will remain of a manageable size, so that permitting authorities will be able to process permit applications and issue permits, which sources must have to construct or expand."

60 Final PSD and Title V GHG Tailoring Rule, June 3, 2010 (75 Fed. Reg. 31514).

61 PSD and Title V Guidance.

62 The federal regulations define "potential to emit" as: "the maximum capacity of a stationary source to emit a pollutant under its physical and operational design." 40 C.F.R. Sections 52.21(b)(4), 51.165(a)(1)(iii), 51.166(b)(4). "Limiting Potential to Emit (PTE) in New Source Review (NSR) Permitting," http://www.epa.gov/reg3artd/permitting/limitPTEmmo.htm; see also, e.g., "Air Permit Reviewer Reference Guide APDG 5944 Potential to Emit Guidance Air Permits Division, Texas Commission on Environmental Quality, December 2008," "Potential to emit is defined in Title 30 Texas Administrative Code (30 TAC) Chapter 122 . . . as the maximum capacity of a stationary source to emit any air pollutant under its physical and operational design or configuration." Id. at 1.

permit program to additional sources or to adjust permit thresholds. The EPA will take comments on the third step in July 2012.

State Implementation

The EPA establishes programs under the Clean Air Act, but the states typically implement and operate the programs after receiving approval from the EPA. Such federally mandated but state implemented state air regulations are delineated in "State Implementation Plans" or "SIPs". State SIPs must be revised to reflect the EPA's new PSD and Title V program changes. Most states have revised or are in the process of revising their own PSD and Title V permitting programs to implement the Tailoring Rule thresholds. The EPA has indicated that there are 13 states that will still need to revise their SIPs in order to be able to regulate GHGs.[63] At least one state (Texas) has indicated it will not regulate GHGs as part of its SIP, and is challenging the authority of the EPA to enforce its GHG requirements in the absence of state regulation.[64] If the EPA determines that states are taking too long to implement changes to their SIP, the EPA has the authority to issue a "Federal Implementation Plan" or "FIP" in its place.[65]

The EPA began regulating GHG emissions in January 2011. For their efforts to succeed, state regulators (i.e., those who will be writing the GHG permits) need to understand the best ways to set "Best Available Control Technology" or "BACT" for GHG. To this end, the EPA issued its "PSD and Title V Permitting Guidance for Greenhouse Gases" in November 2010.[66] It provides technical guidance on setting BACT. BACT is defined in section 169(3) of the Clean Air Act as the "[m]aximum degree of reduction of each pollutant subject to regulation determined on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs."

A BACT determination works on a case-by-case basis. It applies on a site-specific basis but must involve adherence of the following steps:

1) Identify Controls
2) Eliminate Technically Infeasible Controls
3) Rank Remaining Controls by Efficiency
4) Evaluate Other Environmental, Energy, and Economic Impacts
5) Select BACT.

New Source Performance Standards

Under the Clean Air Act, GHG emissions from new and existing sources may also be regulated under the New Source Performance Standards (NSPS) provisions of section 111.[68] NSPSs have been established since the 1970s and are supposed to be reviewed at least every eight years. Under this approach, the EPA issues NSPS requirements for each category of sources that it determines "contributes significantly" to air pollution that may "reasonably be anticipated to endanger public health or welfare."[69]

Under Section 111(b), the EPA sets emissions limitations on *new* and *modified* sources within each source category that it has completed (e.g., Stationary Gas Turbines[70]). The EPA is required to take "into account the cost of achieving

63 On December 13, 2010, the EPA issued a notice stating that:

EPA-approved state implementation plans (SIP) of 13 states (comprising 15 state and local programs) are substantially inadequate to meet Clean Air Act requirements because they do not apply Prevention of Significant Deterioration (PSD) requirements to greenhouse gas (GHG)-emitting sources.

http://edocket.access.gpo.gov/2010/pdf/2010-30854.pdf. These states include Alaska, Arizona, Arkansas, California, Connecticut, Florida, Idaho, Kansas, Kentucky, Nebraska, Nevada, Oregon, and Texas.

64 http://www.law.upenn.edu/blogs/regblog/2011/05/texas-and-epa-battle-over-greenhouse-gas-regulations.html.

65 Section 110(c) of the Clean Air Act, 42 U.S.C. § 7410(c).

66 "PSD and Title V Permitting Guidance For Greenhouse Gases," EPA Office of Air Quality Planning and Standards, November 2010.

67 Id.

68 42 U.S.C. §§7401-7671q, ELR Stat. Clean Air Act §§101-618; 42 U.S.C. §7411(b)(1)(A). Section 111(d) only applies to pollutants—like GHGs—for which there is no standard or NAAQS and which have not been listed as hazardous air pollutants. Criteria pollutants, for which there are NAAQS, have been defined by the EPA under section 108(a) of the Clean Air Act, and include particulate matter, ground-level ozone, carbon monoxides, sulfur oxides, nitrogen oxides, and lead. In the 1990 Clean Air Act amendments, Congress listed 188 toxic air pollutants in section 112(b)(1) of the act. Neither provision includes greenhouse gases. Because GHGs have not been designated as criteria pollutants under section 108 nor listed as hazardous air pollutants under section 112, they qualify for regulation under section 111(d).

69 42 U.S.C. §7411(b)(1)(A). The NSPS requirements must be reviewed and revised at least every 8 years.

70 40 C.F.R. Part 60, subpart KKKK.

such reduction and any non-air quality health and environmental impact and energy requirements…" as the EPA determines.[71]

With regard to *existing* sources, Section 111(d) requires the EPA to issue "guidelines" to the states that they must follow in preparing state plans to meet the standards for existing categories. Under §111(d), states are required to submit a plan to impose NSPS requirements on all existing sources in the state. Guidelines contain targets based on demonstrated controls, emissions reductions, costs, and installation and compliance timeframes. Standards for existing sources can be less stringent than standards for new or modified sources. States have nine months after the publication of guidelines to submit plans for EPA approval.

It is important to understand the relationship between performance standards established under section 111 and preconstruction permitting requirements under the Clean Air Act's PSD provisions, discussed in the context of the Johnson Memorandum and the Tailoring Rule. As noted, PSD provisions require new and modified emitters to meet the BACT standard, described earlier. PSD, however, does not apply to existing facilities. New source performance standards thus end up serving as a "'floor' for BACT determinations."[72]

In December 2010, the EPA entered into a settlement agreement in which it agreed to develop NSPS for new and modified electric generators and emission guidelines for existing electric generators by July 26, 2011. Final regulations are to be promulgated by May 26, 2012.[73]

Potential Flexibility in the EPA's Air Regulations

In each of the air regulations outlined previously there exist opportunities for flexibility in meeting compliance requirements. Under the Clean Air Transport Rule, CATR, the EPA has proposed several market-based compliance mechanisms (i.e., cap-and-trade programs for SO_2 and NOx) that would allow emitters to trade allowances in order to meet compliance obligations in a least-cost manner. Cap-and-trade enables those better situated economically to make the decision to invest in compliance technology to reduce emissions and to sell/trade any extra emissions reductions (allowances) to other affected sources for which investment in technology would be a more expensive option.

In addition to the mechanisms outlined in the previous section, the Mercury/Air Toxics Rule also encourages investment in energy efficiency as a means of mitigating rate effects and lowering consumer electric bills. Limited compliance extensions are also available under Clean Air Act Section 112 and the Mercury/Air Toxics Rule. Although in the Mercury/Air Toxics Rule the initial analysis is relatively prescriptive with regard to required technology, "cost" is one of the factors in the analysis for setting "beyond-the-floor" reductions.

With regard to GHG regulation, the precise purpose of the EPA's Tailoring Rule is to avoid imposing costs too broadly. It directs application of the rule to sources already subject to the standard and then only to larger sources first. The BACT standard applied in PSD permits also takes into account "energy, environmental and economic impacts and other costs." As rulemakings go forward, stakeholders will have the opportunity to provide the EPA with input as to cost effectiveness.

Although no guidance has been issued by the EPA, the analysis under Clean Air Act Section 111 for setting NSPSs allows for the consideration of cost, non-air quality health and environmental benefits, and energy requirements[74]

71 Section 111(a)(1) states:

> *[t]he term "standard of performance" means a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.*

72 For a discussion of the distinction, see "What's Ahead for Power Plants and Industry? Using the Clean Air Act to Reduce Greenhouse Gas Emissions, Building on Existing Regional Programs," F. Litz, N. Bianco, M. Gerrard, and G. Wannier, WRI Working Paper, February 2011, http://pdf.wri.org/working_papers/whats_ahead_for_power_plants_and_industry.pdf.

73 "Under today's agreement with the States of New York, California, Connecticut, Delaware, Maine, New Mexico, Oregon, Rhode Island, Vermont, and Washington, the Commonwealth of Massachusetts, the District of Columbia, and the City of New York; Natural Resources Defense Council (NRDC), Sierra Club, and Environmental Defense Fund (EDF), EPA would commit to issuing proposed regulations by July 26, 2011 and final regulations by May 26, 2012," Settlement Agreements to Address Greenhouse Gas Emissions from Electric Generating Units and Refineries Fact Sheet, http://www.epa.gov/airquality/pdfs/settlementfactsheet.pdf.

74 Sections 111(b)(1)(A), (B).

Water and Solid Waste Regulations

In addition to being subject to various air regulations, electric generators will be affected by the outcome of other rulemakings, which address effluent limitations, cooling water controls, and coal combustion wastes.

Clean Water Act Requirements [75]

There are two Clean Water Act rules in development at the EPA: (1) the Steam Electric Effluent Limitations Guideline (guideline), and (2) the section 316(b) Cooling Water Intake Structures Regulation for Existing Facilities (316(b) rule).

Effluent Rule

Schedule: The EPA is currently collecting technical and financial data for analysis for a proposed rule in 2012.

The Effluent Rule (1982) focuses on the steam electric subcategory of all electric generating activities, including fossil-fueled (coal, oil, gas) power plants. A major focus of the Effluent Rule is on toxic pollutants released into wastewater and ash ponds as part of the flue gas desulfurization (FGD) process. Currently guidelines cover suspended solids, oil and grease from ash ponds, and FGD discharges. While some of the newest power plants have zero liquid discharge (ZLD)[76] systems, most existing power plants release substantial amounts of water used in boilers, cooling systems, and pollution control systems back into the environment. Unregulated pollutants are present in ash ponds, and related discharges include metals that are bio-accumulative (e.g., mercury, selenium, arsenic), nutrients (e.g., nitrates, ammonia), and chlorides.

According to the EPA, the schedule for the development of an effluent rule requires the EPA to collect technical and financial information for analysis, an effort that is now underway. No rule has been proposed, but the EPA intends to issue proposed regulation in mid-2012 and a final rule in late 2013. Dischargers are likely to be required to apply for National Pollutant Discharge Elimination System (NPDES) permits. Compliance is expected to start 3 to 5 years after the final rule, in 2016 to 2018.

316(b) Rule

Schedule: Proposed March 28, 2011; to be finalized by July 27, 2012

Section 316(b) of the Clean Water Act requires that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts.

The purpose of the rule is to "minimize adverse environmental impacts, including substantially reducing the harmful effects of impingement and entrainment."[77] Fish and smaller organisms die because they are either unable to swim away from water intakes and are "impinged" against the screen, or pass through screens and become "entrained" in the cooling system. Thermal pollution is associated with "once through" cooling systems that use water only once as it passes through a condenser to absorb heat and is then discharged. Closed-cycle cooling reuses water by recycling it through recirculating systems or towers without discharging it. The 316(b) rule would set performance standards for fish mortality caused by impingement, and establish a requirement that entrainment standards be developed by facilities on a case-by-case basis.

For nearly twenty years, 316(b) standards have been implemented on a case-by-case basis by water permitting authorities. In 2001, however, the EPA finalized the first of three 316(b) rules. Phase I set standards for new electric generators and other facilities. In 2004, Phase II focused on larger generators. In 2006, Phase III covered remaining facilities subject to section 316(b). The courts found that the EPA's rules did not fully comply with the Clean Water Act, and parts of Phases I, II, and III were remanded to the EPA to be augmented for stricter conditions.[78] The standards in the proposed 316(b) rule are written in response to these cases

75 The discussion of the Guideline and 316(b) Rule is based in part on a presentation by Julie Hewitt, EPA Office of Water, entitled "Clean Water Act Regulations Affecting Electric Utilities," NARUC Webinar, September 24, 2010. http://www.naruc.org/Domestic/EPA-Rulemaking/Docs/EPA%20WATER%20Presentation%20Sept%2024%202010%20_%20Julie%20Hewitt.pdf.

76 Case Study: California's Magnolia Power Project Utilizes HERO/Crystallizer Process For ZLD System. http://www.wateronline.com/downloads/detail.aspx?docid=0186a943-7fcd-4a5b-af88-1becafdaf375.

77 Id.

78 Phase I was challenged in Riverkeeper, Inc. v. U.S. EPA, 358 F. 3d 174, 181 (2d Cir. 2004) ("Riverkeeper I"); Phase II in Riverkeeper, Inc. v. U.S .EPA, 475 F. 3d 83 (2d Cir. 2007) ("Riverkeeper II"), and Phase III in Entergy Corp. v. Riverkeeper Inc., 129 S. Ct. 1498, 68 ERC 1001 (2009) (40 ER 770, 4/3/09); and Conoco Phillips v. EPA (5th Cir. No. 06-60662). See "National Pollutant Discharge Elimination System — Proposed Regulations to Establish Requirements for Cooling Water Intake Structures at Existing Facilities and Amend Requirements at Phase I Facilities," at 14-15, and 38-39 (prepublication version). http://hosting-source.bronto.com/6335/public/Alert_4_4_11.pdf .

and are intended to replace the Phase II regulations and amend the Phase I and Phase III standards.[79]

The proposed 316(b) rule would establish requirements for all existing power generating facilities and existing manufacturing and industrial facilities that (a) withdraw more than 2 million gallons of water per day from waters of the U.S. and (b) use at least 25 percent of the water they withdraw exclusively for cooling purposes.[80] The EPA estimates that roughly 670 power plants would be affected by the rule.

The proposed national standards are to be implemented through National Pollutant Discharge Elimination System (NPDES) permits and would establish national requirements applicable to the location, design, construction, and capacity of cooling water intake structures at these facilities by setting requirements that reflect the Best Technology Available (BTA) for minimizing adverse environmental impact.[81]

Existing Facilities

Impingement

Owner/operators of existing facilities may choose one of two options for meeting BTA requirements for addressing impingement mortality under the EPA's proposed rule.[82] Existing facilities are subject to an upper limit on how many fish can be killed or pinned against intake screens or other parts of facility equipment. Facilities would be allowed to determine which technology would be best suited to meeting this limit. Alternatively, the rule allows facilities to reduce the intake velocity of their cooling water to 0.5 feet per second, a rate at which the EPA presumes fish would be able to swim away from plant cooling water intakes.[83]

Entrainment

To address entrainment mortality, the proposed rule establishes requirements for studies and information as part of the permit application, and then establishes a process by which the best technology available for entrainment mortality would be implemented at each facility. In order to reduce the amount of organisms drawn into cooling water systems, the rule requires existing facilities that withdraw at least 125 million gallons per day to conduct studies to help their permitting authority to determine the level of site-specific control that may be necessary.

New Facilities

The proposed rule would require new units constructed at an existing facility to comply with provisions for impingement and entrainment mortality based on a closed-cycle system. These standards are similar to standards set out for new facilities.[84] This can be accomplished by either including a closed-cycle system or by making any other changes that would result in impingement and entrainment reduction equivalent to the reductions associated with closed-cycle cooling.[85]

Under the terms of a judicial settlement, the EPA is obligated to finalize the rule by July 27, 2012. Compliance dates will be geared to when the EPA issues the final rule. When it becomes effective, technologies to meet the impingement requirements would have to be implemented as soon as possible, but within eight years at the latest. New units would have to comply when they begin operations.

Potential Flexibility in the EPA's Water Regulations

In both water regulations outlined previously, there is potential for flexibility in meeting compliance requirements. There also appear to be significant lead times. No actual effluent rule has been proposed yet, because the EPA is currently gathering technical and financial information. The EPA has indicated its intent to propose a rule in 2012 and a final rule in late 2013, with compliance starting three to five years after that in the 2016 to 2018 timeframe. As development of this rule goes forward, there should be opportunity for comment

79 Id.

80 "In today's proposed rule, EPA is defining the term 'existing facility' to include any facility that commenced construction before January 18, 2002, as provided for in §122.29(b)(4).28." http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/upload/prepub_proposed.pdf at 30. "EPA is proposing to establish January 17, 2002 as the date for distinguishing existing facilities from new facilities because that is the effective date of the Phase I new facility rule. Thus, existing facilities include all facilities the construction of which commenced on or before this date."

81 "Today's proposed rule would apply only to facilities that are point sources (i.e., facilities that have an NPDES permit or are required to obtain one." http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/upload/prepub_proposed.pdf at 80.

82 Id.

83 Id.

84 Id.

85 Id.

regarding compliance alternatives.

The 316(b) rule provides existing sources with choices of how to comply with BTA standards for impingement. For addressing entrainment mortality, the rule provides for facilities to study and develop information as part of the permit application process, and then establishes a process by which the BTA for that facility would be determined. For new facilities or modifications of existing facilities, the EPA allows generators to build a closed-cycle system or to make "other changes that would result in impingement and entrainment reduction equivalent to the reductions associated with closed-cycle cooling."[86]

Coal Combustion Residuals

Schedule: Proposed on June 21, 2010; finalization date TBD.

The EPA proposed a rule on Coal Combustion Residuals (CCRs) from Electric Utilities ("Ash Rule") in June 2010, and has not set a date for a final rule.[87] CCRs are byproducts from the combustion of coal that include fly ash, bottom ash, boiler slag, and flue gas desulfurization materials. In 2008 over 136 tons of CCRs were produced in the U.S.[88] This waste is currently disposed of in various ways. It is placed in approximately 300 CCR landfills or 584 surface impoundments[89] at approximately 495 coal-fired power plants across the nation. It is also placed in mines or "beneficially" used.[90]

Applying its solid waste authority under the federal Resource Conservation and Recovery Act (RCRA), the EPA has proposed two alternative approaches for regulating the disposal of CCRs produced by electric utilities and independent power producers.[91] The first and more stringent approach, designated "Subtitle C," would treat CCRs like hazardous waste.[92] For example, under this approach parties who create, transport, or store CCRs would be subject to various requirements including permitting, ground water monitoring, and financial assurance. Existing landfills would be required to install groundwater monitoring within one 1 year of the effective date of the rule. If monitoring were to show groundwater contamination, remedial action would be required. New or expanded landfills would be required to install composite liners and groundwater monitoring before the landfill begins operation.

Under the less stringent "Subtitle D" approach, CCRs would continue to be classified by the EPA as a "non-hazardous" waste. Facilities would be subject to national minimum criteria governing CCR disposal (see Table D). Subtitle D engineering requirements (e.g., liners and groundwater monitoring) would be similar to Subtitle C. Under either proposal, a "Bevill" exemption from regulation would remain in place for beneficial uses of CCRs.[93] Likewise, mine-filling would not be covered by the proposal.

86 "Proposed Regulations to Establish Requirements for Cooling Water Intake Structures at Existing Facilities," http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/upload/factsheet_proposed.pdf

87 75 Fed. Reg. 35127 (June 21, 2010),http://www.epa.gov/wastes/nonhaz/industrial/special/fossil/ccr-rule/index.htm In its May 2010 pre-published version of the proposed rule, the EPA indicated that it "has not projected a date for a final rule at this time." Discussion of the EPA's proposed Coal Combustion Residual rule based on presentation by Betsy Devlin, Associate Director, U.S. EPA Materials Recovery & Waste Management Division, entitled "Combustion Residuals," NARUC Webinar, September 24, 2010. http://www.bcatoday.org/uploadedFiles/EPA%20Proposed%20Changes%20to%20Coal%20Ash%20disposal.pdf

88 According to ICF International, the current distribution of disposal methods is as follows: 21 percent surface impoundments (wet); 36 percent landfills (dry or moist); 5 percent mines; and 38 percent recycled. "Implications of New EPA Regulations on the Electric Power Industry in the West," Joint Meeting of the State-Provincial Steering Committee and Committee on Regional Electric Power Cooperation, Steven Fine, ICF International, April 12, 2011 at slide 21.

89 The EPA indicates that 75 percent of impoundments are greater than 25 years old and ten 10 percent are greater than 50 years old.

90 According to the EPA, "[b]eneficial use refers to use of material that provides a functional benefit — that is, where the use replaces the use of an alternative material or conserves natural resources that would otherwise be obtained through extraction or other processes to obtain virgin materials." See http://www.epa.gov/wastes/nonhaz/industrial/special/fossil/ccr-rule/ccrfaq.htm#11

91 EPA derives its authority over solid waste disposal from the Resource Conservation and Recovery Act (RCRA), 42 U.S.C.A. §§ 690 et seq.

92 RCRA is divided into subtitles. Subtitles C and D set out the framework for the EPA's solid waste management program. Subtitle C establishes the framework for managing "hazardous" waste (from generation to its disposal), while Subtitle D sets out a system for managing primarily "nonhazardous" waste.

93 In 1980, RCRA was amended to add a provision known as the "Bevill exclusion," to exclude "solid waste from the extraction, beneficiation, and processing of ores and minerals" from regulation as hazardous waste under Subtitle C of RCRA. Id. Section 3001(b)(3)(A)(ii). "EPA, Bevill Amendment Questions" http://www.epa.gov/oecaerth/assistance/sectors/minerals/processing/bevillquestions.html#bevillexclusion

Table D[94]

Key Differences C vs. D		
	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 provisions.
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 (or EPA)	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 CCRs 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

94 75 Fed. Reg. 35127 (June 21, 2010), http://www.epa.gov/wastes/nonhaz/industrial/special/fossil/ccr-rule/index.htm. In its May 2010 pre-published version of the proposed rule, the EPA indicated that it "has not projected a date for a final rule at this time." Discussion of the EPA's proposed Coal Combustion Residual rule based on presentation by Betsy Devlin, Associate Director, U.S. EPA Materials Recovery & Waste Management Division, entitled "Combustion Residuals," NARUC Webinar, September 24, 2010. http://www.bcatoday.org/uploadedFiles/EPA%20Proposed%20Changes%20to%20Coal%20Ash%20disposal.pdf

The EPA is also considering additional alternatives to the Subtitle C or D approaches.[95]

Potential Flexibility in the EPA's CCR Regulations

The EPA's proposed CCR regulations contain significant potential for compliance flexibility. Despite one avenue of regulation (Subtitle C) being especially restrictive, the proposed rule contains a number of less stringent alternatives. It also preserves certain exemptions to CCR regulation. In addition, while the EPA proposed a rule in May 2010, the EPA has decided to refrain for the moment from setting a date for a final rule, leaving regulated entities time to consider alternatives and plan their compliance strategies.

Conclusion

Before any of the EPA's rules are finalized there is the opportunity to shape its outcome through comments and discussions with the EPA and other stakeholders. The change that the EPA recently made in its MACT floor determination mentioned previously is one example of this.[96] Administrative rulemaking is a deliberate and open process. It generally starts with a "proposed" rule or with a "notice of a proposed rulemaking," providing greater notice of agency planning and a larger window for comments. In certain cases, even before issuing a proposed rule, an agency engages in data acquisition and review, as is the case with the current 316(b) and Effluent Rules. The relatively early stage of most of these rules presents an opportunity to utility regulators to encourage their utilities and fellow environmental regulators to participate in the dialogue.

95 (1) An approach referred to as "D Prime" would provide for continued operation of existing surface impoundments until the end of their useful life. Other requirements would be the same as under Subtitle D. (2) An alternative where "wet-handled" CCRs are regulated under Subtitle C and "dry-handled" CCRs under Subtitle D. (3) An approach that would impose Subtitle C regulations unless a state develops enforceable Subtitle D regulations and submits them to the EPA for approval. In that case, if a state were to fail to develop a program within two years or if EPA did not approve one within one year, the federal Subtitle C rule would become effective in that state. (4) An approach that follows Subtitle D requirements unless there were finding of egregious violations of the requirements. In that case CCRs would be considered "special wastes" and treated pursuant to Subtitle C. Devlin.

96 See note 30 above. UARG identified an error in the manner in which the EPA had calculated the MACT floor for mercury, causing the EPA to reset the mercury level from 1 lb/TBtu to 1.2 lb/TBtu.

Part Two
Planning Considerations

Introduction

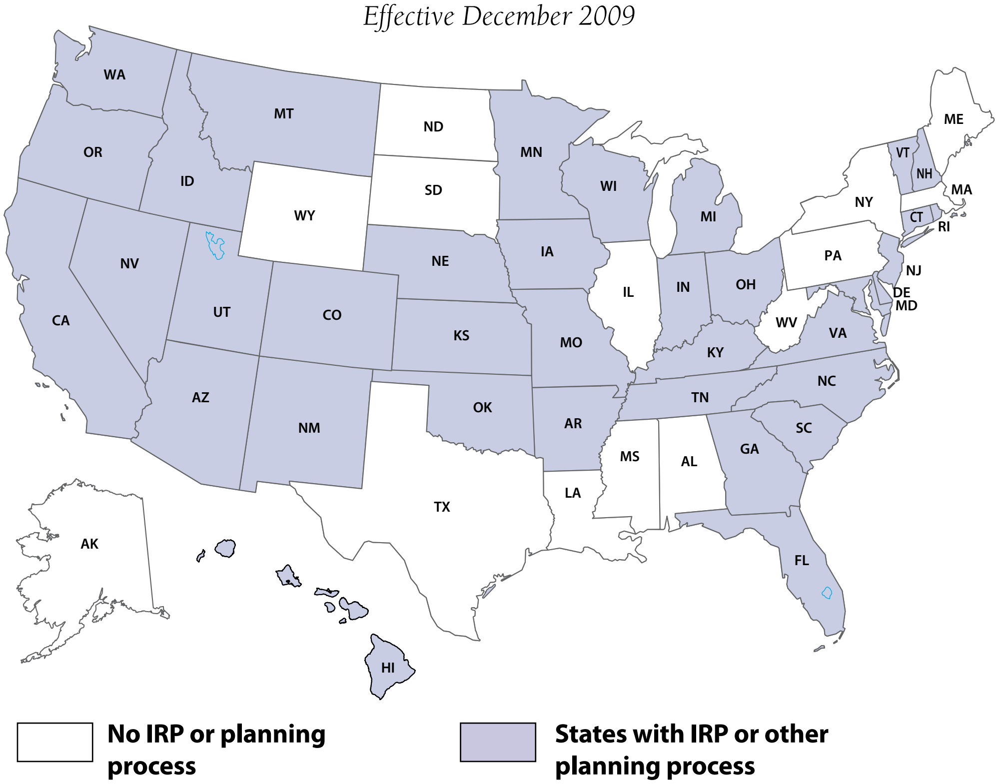
Planning is not new to the utility industry. Utilities plan constantly, and do so with or without the participation of stakeholders and regulatory authorities.[97] What has come to be known as "integrated resource planning" or simply "least-cost planning" has also been around for many years and is practiced in nearly 30 states (Fig.8). It was developed by utility regulators partly in response to large cost overruns (having to do primarily with nuclear facilities) and partly because they saw that an array of alternative resources, including end-use efficiency and renewables, whose economic and environmental characteristics could provide significant system benefits, were being consistently overlooked in traditional utility planning and investment decisions.

The central value in having a utility look ahead and plan, whether or not as part of a formal regulatory process, lies in being able to identify the best resource mix for a utility and its consumers before capital is committed and expenditures are made. The "least-cost" criterion implies "the lowest total cost over the planning horizon, given the risks faced."[99] The best resource mix is one that "remains cost-effective across a wide range of futures and sensitivity cases that also minimize the adverse environmental consequences associated with its execution." [100]

Figure 8 [98]

U.S. States with Integrated Resource Planning or Similar Process

Effective December 2009



97 For example, while the Clean Air Interstate Rule (CAIR) was not finalized until 2005, company-wide planning at the Southern Company for FGD installations started in 2003. Implementation Strategies for Southern Company FGD Projects; Wall, Healy & Huggins; Power Plant Pollutant Control "Mega" Symposium, September 2010 cited in letter to Sen. Thomas Carper, U.S. Senate, from ICAC Executive Director David C. Foerter, November 3, 2010 at 4, http://www.icac.com/files/public/ICAC_Carper_Response_110310.pdf.

98 See the following link for a summary of IRP planning that occurs in the US. http://www.raponline.org/docs/RAP_IntegratedResourcePlanningInUS_2011_03_29.pdf

99 "Electric Regulation in the US: A Guide," Jim Lazar, March 2011 at 73 (Lazar).

100 Id.

To begin to address the challenge associated with the utility sector's compliance with forthcoming EPA health and environmental regulations, utility commissions can urge utility companies to engage in planning to help ensure the reasonableness of their decision-making in this context.[101] Recent Colorado experience provides an excellent example of utility planning and the effective coordination between utility regulators and air regulators in this context. The discussion that follows draws on recent planning experience undertaken by Xcel Energy's Public Service of Colorado and the process managed by the Colorado Public Utilities Commission.

Table E[104]

Xcel Energy's Analysis Framework for Colorado's Clean Air – Clean Jobs Act

1. Data Collection
- Identify Candidate Coal Units
- Emission Control Options and Costs
- Replacement Capacity Options
- Transmission Reliability Requirements

2. Scenario Development
- Meet NOx Reduction Targets
- Feasibility of Emission Controls
- Replace Retired Coal MW
- Transmission Needs Analysis

3. Dispatch Modeling of Scenarios
- Long-term Capacity Expansion Plan
- Cost of Transmission Fixes
- Coal and Gas Price Forecasts
- Customer Load Forecasts

4. Sensitivity Analysis
- Construction Costs
- Coal and Gas Prices
- Emissions Costs (NOx, SO_2, CO_2)
- Replacement MW for retirements
- Addition of renewable resources

Colorado's Planning Process—the Example of Xcel Energy

The "Clean Air – Clean Jobs Act" ("the Act") (see text box), passed in April 2010, anticipates new EPA regulations for criteria air pollutants (NOx, SO_2, and particulates), mercury, and CO_2.[102] It requires Colorado's two investor-owned utilities to consult with the Colorado Department of Public Health and Environment (CDPHE) on utility plans to meet current and "reasonably foreseeable EPA clean air rules," and to submit a coordinated multi-pollutant plan to the state Public Utilities Commission (Commission). Here we consider the example of Xcel Energy's Public Service of Colorado (Xcel).[103]

The Act gave a company like Xcel Energy, owner of Public Service of Colorado, four months to report to the Commission with analysis results and a proposed compliance plan (see Table E). Xcel divided its analysis into four steps. Step one is "data collection." The company identified (a) the coal plants for which the company might take "action" (i.e., install controls, retire, or retrofit for fuel

101 One interesting model of regulatory coordination is found in Michigan. Executive Directive No. 2009 – 2, requires the state environmental regulator, the Michigan Department of Environmental Quality (DEQ), to "conduct analysis of electric generation alternatives prior to issuing an air discharge permit," and as part of this inquiry, the directive requires the Michigan Public Service Commission (PSC) to provide DEQ with technical assistance. Executive Directive No. 2009 – 2, "Consideration of Feasible and Prudent Alternatives in the Processing of Air Permit Applications from Coal-Fired Power Plants," http://www.michigan.gov/granholm/0,1607,7-168-36898-208125--,00.html. The two agencies entered into a memorandum of understanding in which respective roles were articulated: DEQ would undertake air quality determinations, and the PSC would provide assistance related to determining need for new generation, and analyze alternatives, including options for energy efficiency, renewable energy and other generation.http://efile.mpsc.state.mi.us/efile/docs/15958/0001.pdf; "Statutory and Administrative Review of Power Plants in Michigan," NARUC Task Force Webinar 3, State Case Studies, Greg White, Commissioner, Michigan Public Service Commission, December 17, 2010. http://www.naruc.org/Publications/White_%20Michigan%20Coal%20Plant%20Review%20Processes.pdf

102 The "Clean Air – Clean Jobs Act, " HB 10-1365, requires "[b]oth of the state's two rate-regulated utilities, Public Service Company of Colorado (PSCo), and Black Hills/Colorado Electric Utility Company LP, … to submit an air emissions reduction plan by August 15, 2010, that cover[s] the lesser of 900 megawatts or 50% of the utility's coal-fired electric generating units." Legal Memorandum, Office of Legislative Legal Services, March 16, 2011, on H.B. 10-1365 and Regional Haze State Implementation Plan, http://www.leg.state.co.us/clics/clics2011a/cslFrontPages.nsf/FileAttachVw/SIP/$File/SIPMeetingMaterials.pdf.

103 NARUC Climate Policy Webinar 3: State Case Studies, "Dispatches from the Front: The Colorado Clean Air-Clean Jobs Act," Ron Binz, Chairman, Colorado Public Utilities Commission, December 17, 2010, http://www.naruc.org/committees.cfm?c=58; NARUC Task Force on Climate Policy Webinar, Coal Fleet Resource Planning: How States can Analyze their Generation Fleet, "Colorado Case Study," Karen T. Hyde, Vice President, Rates & Regulatory Affairs, and Jim Hill, Director, Resource Planning and Bidding; Xcel Energy, March 11, 2011, http://www.naruc.org/domestic/epa-rulemaking/default.cfm?more=3 (Hyde and Hill). All references to Xcel and Public Service of Colorado's work are based on Hyde and Hill's presentation to NARUC.

104 Adopted from Hyde and Hill.

About the Colorado Clean Air Clean Jobs Act and its Implementation

Colorado, the seventh largest coal producing state in the U.S., passed the "Clean Air Clean Jobs Act" ("the Act") in April 2010, targeting regional haze and ozone, and establishing a 70-80 percent reduction target for NOx from 2008 levels. Denver and Colorado's "Front Range" have been designated under the Clean Air Act as "non-attainment" areas for ground-level ozone, a pollutant created through the interaction of NOx, VOCs and sunlight.

The Act anticipates new EPA regulations for criteria air pollutants (NOX, SO_2, and particulates), mercury, and CO_2, and requires a utility to (a) consult with Colorado Department of Public Health and Environment (CDPHE) on its plan to meet current and "reasonably foreseeable EPA clean air rules," and (b) submit a coordinated multi-pollutant plan to the state Public Utilities Commission (Commission).

The Act mandates that CDPHE participates in the Commission process, and conditions Commission action on CDPHE review of utility proposals, linking the two agencies' actions. The Commission cannot approve a plan that the CDPHE does not agree would meet future Clean Air Act requirements, and the company cannot build anything without the Commission's approval and a certificate of public convenience. The Act also requires the CDPHE's Air Quality Control Commission to incorporate apaproved plans into Colorado's State Implementation Plan (SIP) for addressing regional haze.

Companies are not required to adopt any particular plan, just one that meets CDPHE's requirements and passes muster with the Commission. No plan can jeopardize electric system reliability. The Act encourages companies to evaluate alternative compliance scenarios, but requires each company to develop and evaluate an "all emissions control" case, i.e., a scenario calling for installation of pollution controls on the coal fleet plus an assessment of different ranges of retirements.

The Act encourages utilities to enter into long-term contracts for natural gas supplies. It also allows utilities to recover in rates costs associated with approved long-term contracts, "notwithstanding any change in the market price during the term of the agreement." During its investigation, the Commission approved a long-term supply contract for much of the required gas associated with utilities plans.

Utilities are entitled to recover the full costs to comply with federal Clean Air Act requirements, assuming prudence in preparing and implementing these compliance plans.

The entire process was conducted quickly: the Act was signed into law in April 2010; a Commission docket was opened in May; and a final order was issued in December. In January 2011 the CDPHE adopted changes to the new Colorado SIP.

According to then Commission Chairman Ron Binz, had the legislation not required the two agencies to work together, the air agency would have made its own recommendations to EPA as to what actions would have been necessary for Colorado to meet national standards without having to even consult with the Commission.

switching); (b) emission control options and associated costs; (c) possible generation technologies that would replace retired capacity; and (d) transmission reliability requirements.

Step two is "scenario development." This involves developing combinations of various actions on coal plants and assessing replacement generation (i.e., developing "Capacity Portfolios"), and testing the feasibility of approaches for reducing emissions while maintaining reliable service.

Step three is "dispatch modeling of scenarios." This requires the company to use its "dispatch modeling" capability to evaluate the effects of various scenarios on the company's entire system.

Finally, step four involves the development of sensitivity analyses. At this step, the company performs analyses by varying certain key assumptions to see how the scenarios it developed and modeled under Steps 2 and 3 would perform in different futures.

As Commissions and other decision makers around the country evaluate the readiness of their utility companies and electric generators to comply with the

EPA's forthcoming public health and environmental rules, they can draw upon lessons and insights from the Colorado Clean Air – Clean Jobs example. The overall undertaking required cooperation between the regulatory commission and Colorado's environmental regulator, and significant effort by Xcel. The process, including a commission investigation, company analysis of alternative compliance strategies, issuance of a final order, and subsequent adoption of changes to Colorado's SIP occurred in less than eight months, demonstrating the feasibility of such a cooperative effort and the ability of decision makers to address the challenges related to maintaining system reliability while responding to health and environmental regulatory compliance challenges.

While worst-case scenarios serve a purpose of "bounding" broad statistical modeling efforts, it is important to recognize that such scenarios typically do not get implemented.

Gathering Data

Effects on Existing Capacity

The first step companies should undertake is to acquire relevant and current data. Companies will need to identify which of their existing or planned generation units may be affected by forthcoming EPA regulations. Recent nationwide studies reviewing potential capacity retirements due to forthcoming EPA regulations suggest potential effects on existing resources and possible retirements ranging from 25 to 76 GW by 2020[105] (see Table F). Actual impacts, however, will depend on local conditions and choices that companies and regulators make.

Generally these studies identify either the EPA's 316(b) or Mercury/Air Toxics Rules, or a combination of both, as having the greatest potential to affect plant retirement decisions across the country. They suggest that the CCR and CATR rules can be expected to create additional but lesser effects. It is important to remember, however, that because the EPA had yet to propose the 316(b) or MACT rules (and only proposed them in March 2011), these earlier studies listed in Table F were required to make a number of assumptions about key components of these rules. Accordingly, many drew conclusions based on assumptions that turned out to be quite different than the actual rules that were later proposed by the EPA. In addition, many of the power plants they have identified for retirement are very old, small, or uneconomic and thus may be closed by 2020 with or without new federal regulations.

While worst-case scenarios serve a purpose of "bounding" broad statistical modeling efforts, it is important to recognize that such scenarios typically do not get implemented. The actual EPA regulations— especially the Mercury/Air Toxics Rule and 316(b) rules — contain far more compliance flexibility than most modeling studies assume. The NERC worst-case scenario for the 316(b) rule, for example, projects the need to construct closed-cycle cooling systems at every thermal power plant in the country with an effect on "252 GW (1,201 units) of coal, oil and gas steam generating units across the United States, as well as approximately 60 GW of nuclear capacity (approximately a third of all resources in the U.S (sic))."[108] In its proposed regulation, however, the EPA does not specify more expensive closed-cycle cooling for existing units, and estimates that fewer than 700 facilities will be affected.

Likewise, NERC's worst-case scenario for the Mercury/Air Toxics Rule assumes the rule would apply to "all 1,732 existing and future coal and oil fired capacity (415.2 GW of existing plus another 26 of new planned coal units)" [sic],[109] while EPA estimates are lower (approximately 1,350 coal and oil-fired units at 525 power plants). The October 2010 NERC study assumes that scrubbers, SCR, and carbon injection will need to be installed in power plants, while the EPA's proposed Mercury/Air Toxics Rule contains an extensive number of more flexible compliance options for controlling hazardous air pollutants, many of which are available at lower cost than presumed in the modeling studies. So, despite the value of broad, nationwide analyses, it will be critical for companies and regulators to ascertain

105 Miller at i.

106 (next page) Based on Miller at 14, which, in turn, is based in part on: The Brattle Group, "Potential Coal Plant Retirements under Emerging Environmental Regulations," The Brattle Group, Cambridge, MA (December 8, 2010) p. 11. Available at http://www.brattle.com/_documents/uploadlibrary/upload898.pdf.

107 (next page) Although the M.J. Bradley Study recognizes the presence of additional water, solid waste, and greenhouse gas rules.

108 *2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations* (NERC Study), NERC, October 2010 at iv.

109 Id. at 50.

precisely which units will actually be affected.

In establishing the extent to which local generation resources may be at risk due to pending public health and environmental regulations, utility regulators may want to first determine which generating units are already uneconomic. For example, in its March 2010 "State of

Table F

Comparison of Studies Projecting Amount of Coal Capacity at Risk for Retirement in Response to Future US EPA Regulations[106]

Study	Projected Coal Capacity to Retire or at Risk	Criteria to Identify Coal Capacity at Risk	Rules Considered (Proposed or Potential)
The Brattle Group, *Dec. 2010*	50-65 GW by 2020	***Regulated units:*** 15-year present value of cost > replacement power cost from a gas combined cycle or combustion turbine; ***Merchant units:*** 15-year present value of cost > revenues from	Transport Rule Utility MACT 316(b) Cooling Water Coal Ash
Charles River Associates *Dec. 2010*	39 GW by 2015	In house model (NEEM) optimizing costs of existing capacity and costs of potential new capacity	Transport Rule Utility MACT
NERC, *Oct. 2010*	46-76 GW by 2018 (total fossil fuel capacity, including oil and gas)	Levelized costs (@ 2008 CF) after retrofitting each unit for the environmental regulations compared to the cost of a new gas-fired unit	Transport Rule Utility MACT 316(b) Cooling Water Coal Ash
ICF, *Oct. 2010*	75 GW by 2018	Unknown	Unknown
Credit Suisse, *Sept. 2010*	60 GW	Size and existing controls	Transport Rule Utility MACT
Clean Energy Group, *August 2010 (relied upon ICF/IEE, May 2010, and others)*	25-40 GW by 2015	Age, efficiency, cost of alternative supply	Transport Rule Utility MACT[107]
Bernstein Research, *July 2010*	Net loss of coal generation 181 million MWh (291 million MWh by 2015 reduced by 110 million MWh of new coal to come online in the next five years)	Assumes approx. half of states subject to Transport Rule have emissions budgets suggesting emissions rates of 0.36 lbs/MMBtu or less, implying widespread need for scrubber installation, and further, that most of the generation in these states that falls into this category is unscrubbed coal plants smaller than 200 MW (approx. 24 GW). Presumes MACT standard requires installation of SO_2 scrubbers.	Transport Rule Utility MACT
ICF/INGAA, *May 2010*	50 GW	Age, efficiency, and existing controls	Unknown
ICF/IEE, *May 2010*	25-60 GW by 2015	Cost of retrofitting coal plant compared to cost of new gas combined cycle	Unknown

the Market Report," PJM's Independent Market Monitor identifies 11 GW of coal units at risk because they "did not recover avoidable costs even with capacity revenues."[110] In traditionally regulated markets, commissions will need to engage with individual companies and make this inquiry, although they may have relevant data from recent rate cases or other litigation.

Part of establishing a list of the facilities that are likely to be affected will require a determination of what controls are already in place and how they are relevant for compliance

Figure 9[111]

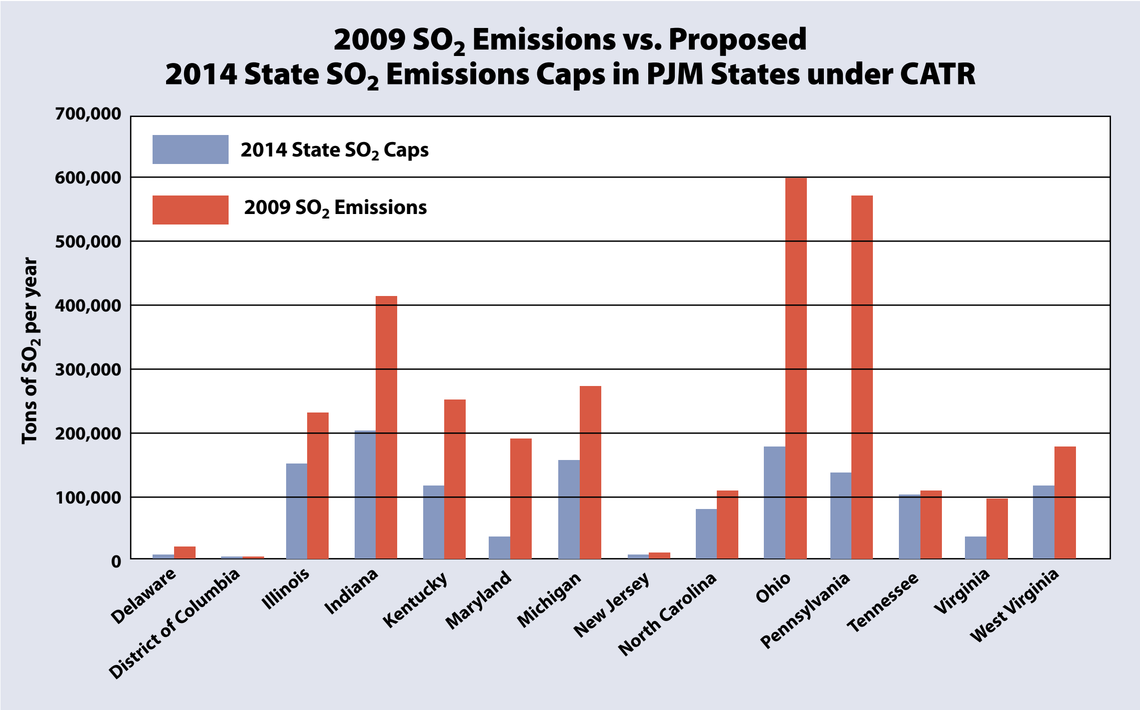
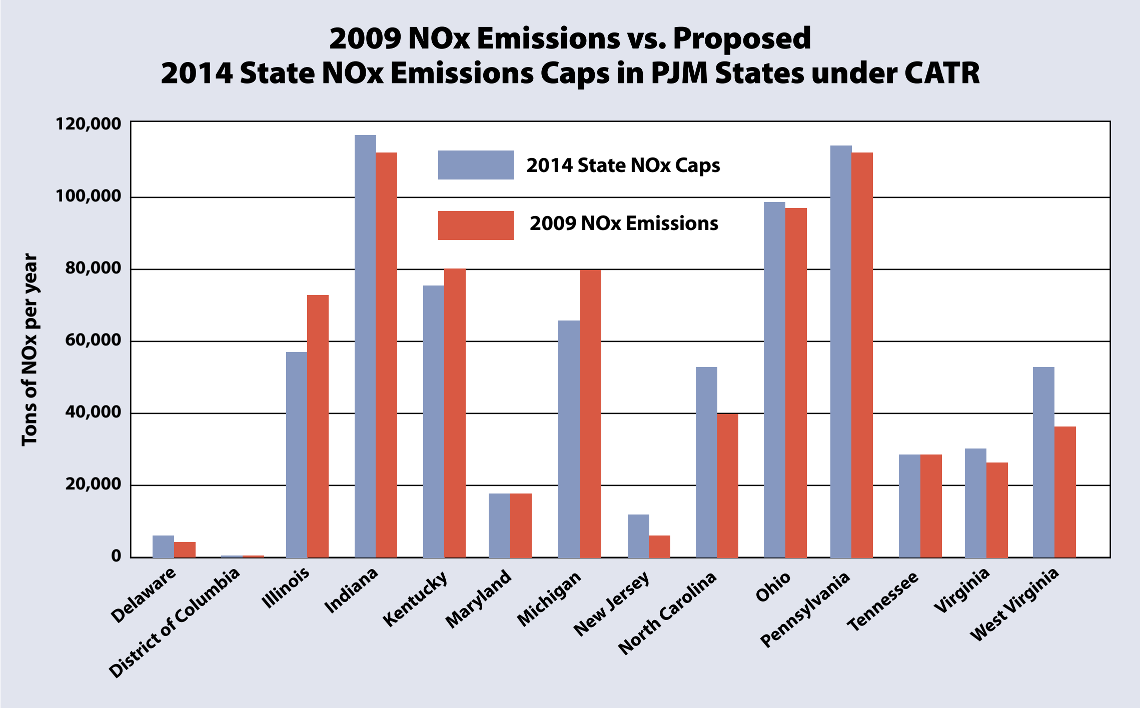


Figure 10[112]



In traditionally regulated markets, commissions will need to engage with individual companies and make this inquiry, although they may have relevant data from recent rate cases or other litigation.

110 M.J. Bradley at 20, citing to PJM, *State of the Market Report*, Vol. 1, March 11, 2010, at 21.

111 Adapted from "Thinking about Potential Reliability Consequences in PJM from Forthcoming EPA Rules" and comments of Paul M. Sotkiewicz, Ph.D., Chief Economist, PJM Interconnection, speaking at the Bipartisan Policy Center's "Environmental Regulation and Electric System Reliability, Workshop II: Reliability Impacts of Power Sector Developments," December 7, 2010 (Bipartisan Center, "Reliability Impacts"), http://www.bipartisanpolicy.org/news/multimedia/2010/12/10/reliability-impacts-power-sector-developments-power-sector-developments-a.

112 Id.

under programs being proposed. For example, the relatively stringent SO_2 limitations in CATR are expected to drive investment decisions, whereas the relatively relaxed NOx limits, on the other hand, may not (see Figs. 9 and 10).

This figure shows that 2009 NOx emissions in 9 of the 14 PJM jurisdictions are already below the proposed 2014 NOx emissions caps that the EPA would impose under CATR.

In further determining which resources will be affected by forthcoming rules, and what actions (i.e., retirement, fuel-switching, or installation of environmental controls) companies may need to take in response, it is important to remember that in the next several years there will be a significant generation surplus across the country.[113] Relying on data in part from NERC's "2009 Long-Term Reliability Assessment: 2009-2018," the Clean Energy Group indicates that "on an aggregate basis across all NERC regions, the electric sector is expected to have over 100 GW of surplus generating capacity in 2013…."[114] (see Table G)

In Xcel's review of Public Service of Colorado's fleet, the company identified eight separate coal units for which the company decided to "take action" (i.e., to retire, control, or switch to natural gas). These units, in general, tended to be older, smaller, and less efficient. They also faced higher fuel costs. Larger and newer coal units with lower fuel costs, and which typically burned Powder River Basin coal (i.e., coal with lower sulfur, mercury, and chlorine content) were targeted for retrofit with emissions controls.

Table G

Estimated Reserve Margins in All NERC Regions:
Adequate Generating Capacity, Clean Energy Group[115]

Region	Projected Reserve Margin in 2013	Cushion Above NERC Target Reserve Margin in 2013
TRE – Texas Regional Entity	23.9%	7.8 GW
FRCC – Florida Reliability Coordinating Council	28.6%	6.1 GW
MRO – Midwest Reliability Organization	22.1%	3.2 GW
NPCC – Northeast Power Coordinating Council	24.4%	5.9 GW
RFC – Reliability First Corporation	24.3%	17.1 GW
SERC – Southeast Reliability Corporation"	26.3%	23.9 GW
SPP – Southwest Power Pool	30.3%	7.7 GW
WECC – Western Electricity Coordinating Council	42.6%	35.6 GW
Total		**107.3 GW**

Controls[116]

As companies review their list of generation resources that will potentially be affected by the forthcoming EPA regulations, they will have to assess the range of relevant control strategies available to each. As explained earlier, assumptions about environmental controls are dictated largely by the standards, how they are implemented, the compliance timeframes in the regulations, and the degree of flexibility provided in each rule. CATR will require investment in controls for NOx (Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR) and for SO_2 (flue-gas desulfurization (FGD) and dry sorbent injection (DSI).[117] However, according to a Bipartisan Policy Center presentation by James Staudt, the region-wide effort required for compliance with CATR will be a more modest undertaking when compared with the investment and construction associated with the EPA's NOx SIP call and Phase I of its Clean Air Interstate Rule.[118]

113 The EPA Scenario utilized data from NERC's *2009 Long-Term Reliability Assessment* rather than NERC's October *2010 Long-Term Reliability Assessment.* In the more recent NERC report, electricity generation capacity numbers are higher than those relied upon in the *EPA Scenario.* For example, the *2010 Long-Term Reliability Assessment*'s total U.S. "Existing Certain & Net Firm Transactions" (932,071 MW) exceed the same figures from the *2009 Long-Term Reliability Assessment* (925,336 MW) by 6,735 MW.

114 M.J. Bradley at 8; "2009 Long-Term Reliability Assessment: 2009-2018," NERC, October 2009.

115 Table 2 Estimated Reserve Margins in All NERC Regions: Adequate Generating Capacity. Id. at 9.

116 See Appendix for a description of environmental controls available for criteria and toxic air pollutants.

117 "Clean Air Act Regulation, Technologies, and Costs," Power Sector Environmental Regulations Workshop, David C. Foerter, Executive Director, Institute of Clean Air Companies (ICAC), October 22, 2010.

The proposed Mercury/Air Toxics Rule contains significant flexibility provisions, including facility-wide and monthly emissions averaging, the use of surrogate pollutants, and fuel-switching to coals with lower mercury or chlorine content. The rule also encourages investment in energy efficiency as a means of mitigating rate effects and lowering consumer electric bills. Units that already have scrubbers can be expected to have less difficulty complying with the Mercury/Air Toxics Rule.[119] They are likely to be able to meet acid emissions requirements and, depending on coal type, may be able to meet mercury removal limits.[120] Un-scrubbed units will need to install electrostatic precipitators (ESPs) or fabric filters for particulates or make use of alternative sorbents such as activated carbon or halogen additions for mercury[121] and dry sorbent injection (e.g., Trona, Sodium Bicarbonate, or Hydrated Lime, i.e., dry-scrubber technologies) for strong (hydrochloric and hydrofluoric) acids.[122]

In the 316(b) rule, the EPA concluded that closed-cycle systems and cooling towers would not constitute the "best technology available" for addressing impingement and entrainment at existing generation facilities. Instead, it proposed an array of alternatives:

> *EPA based the impingement mortality and entrainment (I&E) performance standards on a combination of technologies because it found no single technology to be most effective at all affected facilities. For impingement standards, these technologies included: (1) fine and wide-mesh wedgewire screens, (2) barrier nets, (3) modified screens and fish return systems, (4) fish diversion systems, and (5) fine mesh traveling screens and fish return systems. With regard to entrainment reduction, these technologies include: (1) aquatic filter barrier systems, (2) fine mesh wedgewire screens, and (3) fine mesh traveling screens with fish return systems.*[123]

Depending on the exact subtitles and provisions under which the EPA chooses to regulate residuals, the CCR rule could impose requirements for containers, tanks, and containment building at storage sites. Surface impoundments and landfills, depending on whether they are built before or after the rule is finalized, will be required to meet different land disposal restrictions, including liner requirements. Post-closure requirements will also vary. Subtitle C facilities will be monitored by the State and EPA, and Subtitle D facilities will be self-implementing. There may also be a significant difference between implementation timeframes under the two subtitles. Federal permitting and enforcement under Subtitle C would require 100 percent compliance in a limited timeframe, and under Subtitle D, state enactment and enforcement might take longer.[124] There is also concern that a hazardous waste designation would stigmatize potential beneficial reuses of CCR. That treatment might result not only in tighter regulation of landfills and impoundments, but, due to limited reuse, more material going into them.

In Xcel's case, its engineering department proposed the controls they considered appropriate for the units the company concluded should be controlled for air emissions. On these units, NOx is subject to combustion controls: low NOx burners and "overfire air."[125] The company's analysis also included consideration of how much additional

118 "Surviving the Power Sector Environmental Regulations," James Staudt, Ph.D., The Bipartisan Policy Center's National Commission on Energy Policy (NCEP), October 22, 2010 (Staudt).

119 Id.

120 Id.

121 Id. Activated carbon is more absorbing because it is more porous. This capacity can be enhanced by further treating carbon with a compound that reacts chemically with mercury. Halogen converts mercury to mercuric halide, and this can be absorbed by coal ash and dry flue gas desulphurization solids. Combining halogen and activated carbon also presents a lower cost approach to other sorbents such as bromated activated carbon. See "Options for High Mercury Removal at PRB-fired Units Equipped with Fabric Filters with Emphasis on Preserving Fly Ash Sales," Paradis et al. http://secure.awma.org/presentations/Mega08/presentations/6a-Dutton.pdf; see also NALCO/Mobotec, http://www.nalcomobotec.com/expertise/mercury-control.html

122 Like other sorbents, these are injected into the furnace (i.e., upstream from the particulate removal device). They react with the acid gas and are caught by ESPs or fabric filters.

123 Prepublication version, March 28, 2011 at 30-31, http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/upload/prepub_proposed.pdf

124 "Implications of New EPA Regulations on the Electric Power Industry in the West," Joint Meeting of the State-Provincial Steering Committee and Committee on Regional Electric Power Cooperation, Steven Fine, ICF International, April 12, 2011 at slide 21.

125 Overfire air is also referred to as "air staging," a process that removes air (i.e., limits oxygen availability) from burners early in the combustion process and reintroduces it later on. "Often the physical arrangement dictates replacing the staged air through ports located above the combustion zone; hence the name overfire air is commonly applied to such systems. The layout of a combustion system and furnace, however, may necessitate supplying staged air at the same elevation or below the burner zone, such that [overfire air] is something of a misnomer." "Auxiliary Equipment: Overfire Air Systems" Babcock & Wilcox, http://www.babcock.com/products/auxiliary_equipment/overfire_air_systems.html

reduction would be available through the use of controls such as SCR. This included consideration of capital costs associated with installing these additional controls and also the fixed costs associated with operations and maintenance.

It should be noted that, in addition to gathering data on costs associated with various controls and control strategies, commissions may also want to consider the potential local economic stimulation associated with generator investments in environmental controls.[126] According to a recent study, the CATR and Mercury/Air Toxics Rules will provide

> *[L]ong-term economic benefits across much of the United States in the form of highly skilled, well paying jobs through infrastructure investment in the nation's generation fleet. Significantly, many of these jobs will be created over the next five years as the United States recovers from its severe economic downturn.*[127]

Replacement Capacity/Fuel Switching

It is important for companies to identify their options for replacement capacity. There are numerous alternative capacity options nationwide, including natural gas, renewable resources, and various demand-side resources like energy efficiency, demand-response, and distributed generation.

Natural Gas

The availability and favorable pricing of natural gas over time makes it a significant alternative to certain types of coal capacity, particularly for older units used only seasonally or for meeting peak demands.[128] According to EIA's Annual Energy Outlook 2011 (AEO2011), "typically, trends in U.S. coal production are linked to its use for electricity generation, which currently accounts for 93 percent of total coal consumption."[129] However, "[f]or the most part, the reduced outlook for coal consumption in the electricity sector is the result of lower natural gas prices that support increased generation from natural gas in the AEO2011 Reference case."[130]

In addition to the potential for new gas capacity, the nation already has a significant amount of underutilized existing gas capacity. Relying on EIA-860 and EIA-923 data from 2008, M.J. Bradley & Associates reports that coal plants larger than 500 MW were used 67 percent of the time, while gas plants in the same category were used only 35 percent of the time.[131] The same trend exists for plants between 200 and 500 MW: 60/32 percent, coal and gas, respectively.[132] For plants smaller than 200 MW, the split was 45/30 percent coal and gas.[133]

Generally, smaller coal plants are most susceptible to fuel switching for many reasons. First, they have relatively high retrofit costs per megawatt of capacity. Second, they tend to be older units, with lower fuel efficiency, so they are used fewer hours per year, making the retrofit costs per megawatt-hour of energy produced higher still. Third, they have high operating costs due to the staffing requirements that are independent of unit size.

There is also significant new capacity currently being brought online today: "over 55 GW of proposed generation in advanced stages of development in the queue for 2013" across all NERC regions.[134] Most of this consists of renewable and natural gas generation. The electric industry also has experience in bringing on significant amounts of new generation capacity in a short time span. For example, 270 GW of natural gas was added to the grid between 2000 and 2004[135] (see Fig. 11).

126 See "New Jobs, Cleaner Air, Employment Effects Under Planned Changes to the EPA's Air Pollution Rules," CERES, University of Massachusetts Political Economy Research Institute, James Heintz, Heidi Garrett-Peltier, and Ben Zipperer, February 2011, www.ceres.org/epajobsreport

127 Id. at 1.

128 This also assumes continuing community support for extraction practices.

129 AEO2011 Early Release Overview, http://www.eia.gov/forecasts/aeo/pdf/0383er(2011).pdf . Annual Energy Outlook (Projections in the Annual Energy Outlook 2011 [AEO2011] Reference case focus on the factors that shape U.S. energy markets in the long term. Under the assumption that current laws and regulations will remain generally unchanged throughout the projections, the AEO2011 Reference case provides the basis for examination and discussion of energy market trends and the direction they may take in the future.) Id.

130 Id. For example, comparing AEO2010 and AEO2011 Reference cases, 2008-2035, EIA reduced its projected prices of domestic natural gas at wellhead (dollars per thousand cubic feet) from $6.35 to $5.46 (2025) and from $8.06 to $6.53 (2035).

131 M.J. Bradley Study at 11, Table 4 – Estimated Utilization of U.S. Coal and Gas Plants (CCGT) by Region (2008).

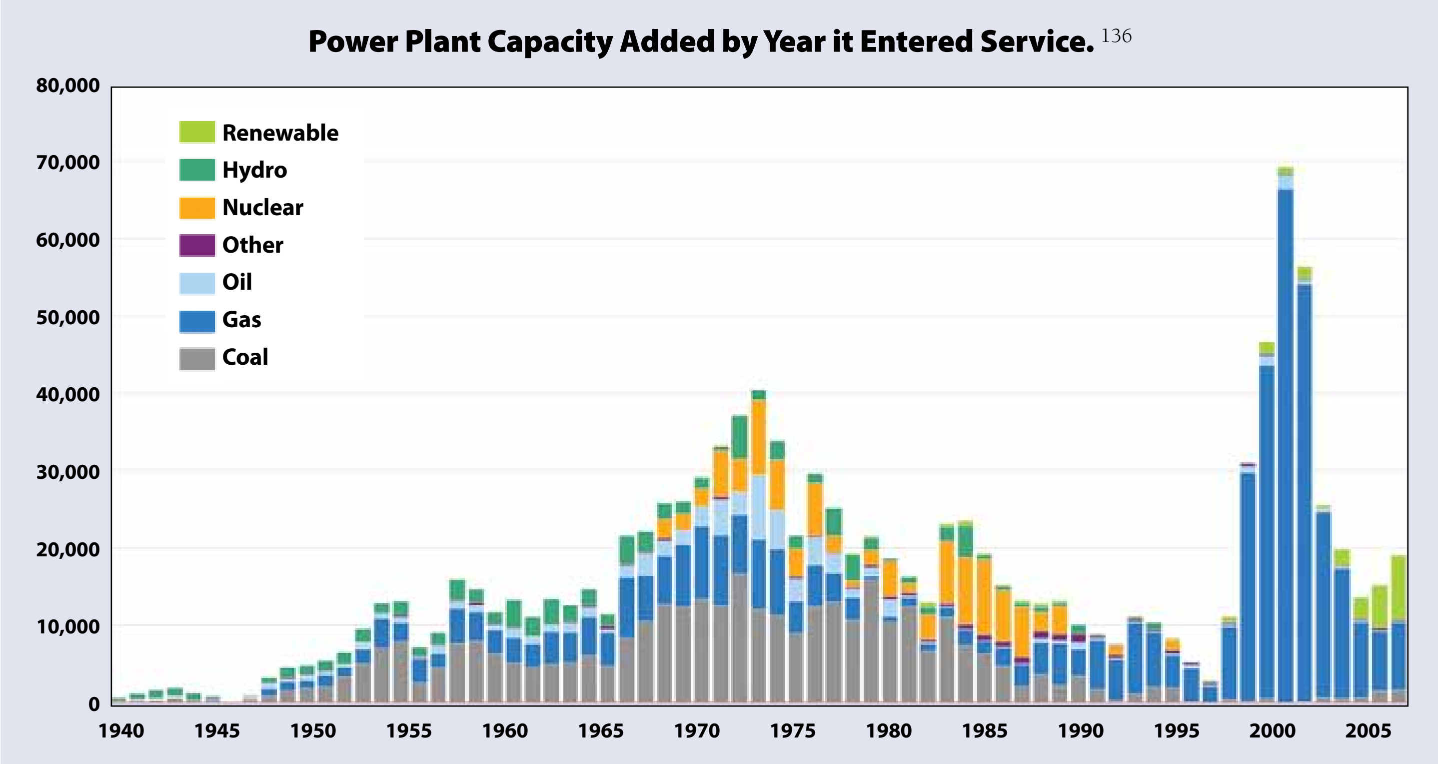
132 Id.

133 Id.

134 Id. at 9.

135 Id. at Fig. 3.

Figure 11



In this context, there is another attractive aspect of generating electricity with natural gas. Because natural gas generation is not subject to the Mercury/Air Toxics Rule, coal units that switch to gas will, likewise, not be subject to obligations under the rule.[137] According to Charles River Associates, of the 264 GW of coal capacity in the Eastern Interconnection, about 41 GW have access to natural gas pipelines.[138]

Xcel in Colorado analyzed fuel switching to natural gas, and concluded that natural gas combined cycle would be the most suitable candidate for replacement capacity by the company.[139] Their analysis included an assessment of ongoing O&M costs and impacts on heat rates. More specifically, while this sort of switch can eliminate costs associated with coal handling and also reduce associated maintenance costs, there may be an associated heat-rate penalty. To the extent a plant would be retired earlier than its book life, the company also noted that it would want to accelerate the depreciation of the plant's remaining book value. Regulators will need to consider these issues very carefully.[140]

Demand-Side Resources

Demand-side resources can also play a significant role in economically and reliably meeting capacity requirements. These are customer-based resources — energy efficiency, demand response, and distributed generation — that reduce energy needs at various times of the day and year, across a few or many hours. According to M.J. Bradley & Associates,"over the years, the industry has recognized that decreasing load

136 Id. citing to CERES, et al., *Benchmarking Air Emissions of the 100 Largest Electric Power Producers in the United States*, http://www.ceres.org/Document.Doc?id=600, June 2010.

137 "A Reliability Assessment of EPA's Proposed Transport Rule and Forthcoming Utility MACT," Charles River Associates, Dr. Ira Shavel, Barclay Gibbs, Charles River Associates, December 16, 2010 at 23.

138 Id.

139 The company also considered renewable resources and demand-side management.

140 See Lazar/Farnsworth paper on Regulatory Treatment of Emission Costs. www.raponline.org/docs/RAP_RegulatoryTreatmentofEmissionsCosts_2011_05.pdf

requirements can be more efficient and economical than increasing supply by dispatching generation."[141]

Energy Efficiency

Energy efficiency avoids load altogether over the lifetime of efficiency measures and can reduce supply capacity challenges. Energy efficiency programs reduce overall customer energy use through investment in more efficient end-use technologies like lighting, pumps, and motors, and also through other conservation measures.[142] M.J. Bradley & Associates reports that, "the total budget for all US ratepayer-funded [energy efficiency and demand response] programs has increased 80 percent since 2006 to $4.4 billion in 2009." Further, they indicate that these programs saved nearly "105,000 gigawatt hours ("GWh") of electricity in 2008," and that by 2018, new energy efficiency programs "are expected to reduce summer peak demands by almost 20,000 MW."[143]

The average cost of energy efficiency investments by utilities is significantly lower than the average cost of generated electricity. Its cost is also generally lower than retrofit and fuel costs associated with continued operation of existing power plants. Efficiency Vermont, for example, reports the average cost for its statewide energy efficiency programs to be 1.1¢ to 4.1¢/kWh.[144]

Demand Response

Demand response (DR) programs are designed "to elicit changes in customers' electric usage patterns."[145] One general approach to DR that can be characterized as "price-based" varies electricity prices to affect existing patterns of customer consumption.[146] "Incentive-based" approaches to DR seek to reward electricity users for reducing their consumption or for granting electricity providers control over a customer's electrical equipment. There are various types of programs within these two broad categories of DR (see Table H).

Table H

Common Types of Demand Response Programs[147]

Price Options	Incentive- or Event-Based Options
Time of Use Rates — Rates with fixed price blocks that differ by time of day	***Direct load control***— Customers receive incentive payments for allowing the utility a degree of control over certain equipment
Critical Peak Pricing — Rates that include a pre-specified, extra-high rate that is triggered by the utility and is in effect for a limited number of hours	***Demand bidding/buyback programs*** — Customers receive incentive payments for load reductions when needed to ensure reliability
Real-time Pricing — Rates that vary continually (typically hourly) in response to wholesale market prices	***Emergency demand response programs*** — Customers receive incentive payments for load reductions when needed to ensure reliability
	Capacity market programs — Customers receive incentive payments for providing load reductions as substitutes for system capacity
	Interruptible/curtailable — Customers receive a discounted rate for agreeing to reduce load on request
	Ancillary services market programs — Customers receive payments from a grid operator by committing to curtail load when needed to support operation of the electric grid

141 M.J. Bradley at 11.

142 Id. at 15 citing to Consortium for Energy Efficiency, *The State of the Efficiency Program Industry: Budgets, Expenditures, and Impacts,* 2009, at 7; NERC, *2009 Long-Term Reliability Assessment: 2009-2018,* October 2009 at 12.

143 Id.

144 Efficiency Vermont. Year 2010 Savings Claim. April 1, 2011. http://www.efficiencyvermont.com/docs/about_efficiency_vermont/annual_reports/2010_Savings_Claim.pdf

145 "National Action Plan for Energy Efficiency," (2010), *Coordination of Energy Efficiency and Demand Response,* Charles Goldman (Lawrence Berkeley National Laboratory), Michael Reid (E Source), Roger Levy, and Alison Silverstein. www.epa.gov/eeactionplan at 2.3 ("Goldman et al. 2010") at 2.2.

146 This distinction is made by Goldman et al. 2010

147 Based upon "Table 2-2. Common Types of Demand Response Programs," Goldman et al. 2010 at 2.3, (citations omitted).

According to Goldman et al, the large majority (over 90 percent) of DR offered in the U.S. is either incentive-based or event-driven and can be invoked in response to "a variety of trigger conditions." These conditions might include, for example, congestion conditions in a power grid or requirements related to operational reliability.[148] The Clean Energy Group reports that demand response in PJM has "increased five-fold in the past five years and continues to grow," and that, in the most recent capacity auction over 9,000 MW cleared.[149] According to the Federal Energy Regulatory Commission (FERC)'s recently released National Action Plan on Demand Response, demand response "tripled in recent years in the New England Region."[150]

Distributed Generation

Generating electricity on the customer premises and in some cases using the generation process's waste heat to serve on-site thermal needs (i.e., combined heat and power, or "CHP") is another demand-side strategy. Between 2005 and 2010, the states added approximately 1,743 MW of new CHP.[151] In addition, grid-connected photovoltaic capacity installed in the residential sector has risen steadily in the past decade, increasing by about four times between 2006 and 2009.[152]

Distributed generation saves not only generation capacity, but also transmission and distribution capacity, the associated line losses, and utility reserve capacity needs. One kilowatt of distributed capacity can replace as much as 1.4 kW of utility central generation.[153]

In Colorado, Xcel also reviewed its options for adding additional renewable resources (wind and solar) and demand side management. More recently, the Commission decided to increase Xcel's proposed energy-savings goals of 7 percent to 30 percent, in part on the basis of the energy-savings potential study developed by the company.[154]

Retirement and Reliability

As companies and others consider the possible retirement and replacement of generation resources, the issue of system reliability arises. Intuitively people may think they understand the term "reliability." After all, most of us drive a car and we know the difference between one that is reliable and one that isn't. So when someone discussing the electric system mentions "reliability," we think we have a general sense of what the person may be talking about.

Strictly speaking, however, reliability "is a measure of the transmission system's ability to meet end-use demand during all hours."[155] According to NERC, the organization responsible for ensuring bulk power system reliability in the U.S., "reliability" "consists of two fundamental concepts:

> ***"Adequacy"*** *is the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components; [and]*
>
> ***"Operating reliability"*** *is the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components.*[156]

NERC further defines "resource adequacy" as the "ability of the electric system to supply the aggregate electrical demand

148 Id.

149 Id. at note 37 and accompanying text, citing to PJM, *Demand Response To Play Significant Role In Meeting PJM's Higher Summer Peak Electricity Use*, http://pjm.com/~/media/about-pjm/newsroom/2010-releases/20100505-summer-2010-outlook.ashx (accessed August 6, 2010); note 38 citing to "PJM, 2013/2014 RPM Base Residual Auction Results," at 1.

150 Id. at note 36 citing to The Federal Energy Regulatory Commission Staff, *National Action Plan on Demand Response,* June 17, 2010, at p. 7.

151 ACEEE, The 2010 State Energy Efficiency Scorecard, October 2010.

152 Interstate Renewable Energy Council, US Solar Market Trends 2009, July 2010.

153 Jim Lazar, Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements, The Regulatory Assistance Project, July 2011, http://www.raponline.org/docs/RAP_Lazar_ValuingtheContributionofEE_2011_07

154 "Colorado Utility Commissioners Raise the Bar on Energy Savings for Xcel Energy Customers," Southwest Energy Efficiency Project, March 31, 2011, http://swenergy.org/news/press/documents/PRESS%20RELEASE%20-%20CO%20Utility%20Commissioners%20Raise%20Bar%20on%20Energy%20Savings%2003-31-11.pdf

155 "Resource Adequacy — Alphabet Soup!," Stanford Washington Research Group Policy Research, Stanford Group Company, Electricity Policy Bulletin, Christine Tezak, (Tezak) June 24, 2005, at 2. http://www.hks.harvard.edu/hepg/Papers/Stanford.Washington.Resource.Adequacy.pdf.

156 North American Electric Reliability Corporation (NERC), "Definition of "Adequate Level of Reliability," approved by Operating Committee and Planning Committee at their December 2007 OC and PC meetings, at 5, citations omitted. http://www.nerc.com/docs/pc/Definition-of-ALR-approved-at-Dec-07-OC-PC-mtgs.pdf.

and energy requirements of the end-use customers at all times."[157] Resource adequacy standards around the U.S. are set by Regional Electric Reliability Councils for generation adequacy, typically based on a "1-day-in-10-years Loss of Load Expectation."[158]

In practice, determining impacts on reliability is less a matter of broad statistical analysis and more of a focus on local conditions in specific regions and markets.

While much of the recent debate stemming from the NERC Study relies upon the term "reliability," it is actually "adequacy" that NERC modeled in its *2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations.* Recognizing the limited nature of that analysis, NERC noted that:

> *Resource deliverability, outage scheduling/construction constraints, local pockets of retirements, and transmission needs may also affect bulk power system reliability. While these issues were not studied in this assessment, industry will need to resolve these concerns.*[159]

In practice, determining impacts on reliability is less a matter of broad statistical analysis and more of a focus on local conditions in specific regions and markets. Ensuring the adequacy of transmission so that generation capacity is deliverable without violating reliability criteria is an example of this more localized analysis. It calls for modeling power flows in parts of the grid to determine the specific circumstances under which reliability criteria may be affected.

If a generating unit is critical for maintaining reliability under certain scenarios, it may qualify for reliability-must-run (RMR) status. "RMR contracts are out-of-market contractual obligations paid to a facility that otherwise would meet the criteria for retirement but that the grid operator wants to maintain in order to facilitate reliability."[160] RMR status also entitles the generator to distinct compensation and dispatch practices. RMR is not a permanent designation and alternatives to meeting reliability standards are encouraged.[161] Market participants also argue that the extensive use of RMR contracts constitutes a barrier to the entry of new (transmission or supply) resources, unnecessarily prolonging the lives of less efficient and dirty resources.[162]

157 NERC Glossary of Terms Used in Reliability Standards, April 20, 2009, at http://www.nerc.com/docs/standards/rs/Glossary_2009April20.pdf. http://www.raponline.org/docs/RAP_Gottstein_Schwartz_RoleofFCM_Experienceand-Prospects2_2010_05_04.pdf.

158 Tezak at 2. See ISO New England Planning Procedure No. 3, Reliability Standards for the New England Area Bulk Power Supply System, Effective Date: March 5, 2010.

Resources will be planned and installed in such a manner that, after due allowance for the factors enumerated below, the probability of disconnecting noninterruptible customers due to resource deficiency, on the average, will be no more than once in ten years. Compliance with this criteria shall be evaluated probabilistically, such that the loss of load expectation [LOLE] of disconnecting noninterruptible customers due to resource deficiencies shall be, on average, no more than 0.1 day per year.

a. The possibility that load forecasts may be exceeded as a result of weather variations.

b. Immature and mature equivalent forced outage rates appropriate for generating units of various sizes and types, recognizing partial and full outages.

c. Due allowance for scheduled outages and deratings.

d. Seasonal adjustment of resource capability.

e. Proper maintenance requirements.

f. Available operating procedures.

g. The reliability benefits of interconnections with systems that are not Governance Participants.

h. Such other factors as may from time-to-time be appropriate.

159 NERC Study at 6.

160 Tezak at note 11.

161 Reliability must run status, however, is not permanent. See, e.g., FERC, Docket 133 FERC ¶ 61,230, Order ER10-2477-000, December 16, 2010. In this order addressing contentions associated with the results of New England ISO's Forward Capacity Auction, FERC reviewed the ISO's conclusion that de-listing (i.e., retirement) Salem Harbor Units 3 and 4 would "jeopardize the reliable operation of the bulk power system and would result in violations of the criteria of the North American Electric Reliability Corporation (NERC), the Northeast Power Coordinating Council (NPCC), or ISO-NE." Id. at 5. FERC acknowledged that the ISO Tariff requires ISO-NE to "identify alternatives to resolve" the reliability need for a rejected de-list bid and identify "the time to implement those solutions" with the Reliability Committee "prior to the start of the New Capacity qualification period" for the next Forward Capacity Auction." Id. FERC ordered ISO-NE to submit a compliance filing "identifying alternatives to resolve the reliability need for Salem Harbor Units 3 and 4 and the time to implement those solutions," or to provide "an expedited timeline for identifying and implementing alternatives" Id. at 11.

162 Tezak at note 11.

Plant Retirements in Organized Markets and in Traditional Service Territories

In organized markets like PJM or the New England ISO, electric generation is made available through resource auctions and the establishment of economic merit order. For example, in New England's forward capacity market, in order to get paid, a generator needs to submit a bid for its unit, and that bid must clear through the auction. Once the bid is successful, i.e., the generator has a position and a price, the generator must deliver the resource for the time and the capacity bid. If the generator fails to deliver on its bid, it could face a penalty, and certainly would forego revenues for capacity it has failed to deliver.

In this context, retirement, in effect, is removing a unit from a current or future auction, and is referred to as "de-listing." In the New England ISO's Forward Capacity Market, existing resources are able to leave the market by submitting a "de-list" bid. All de-list bids are subject to a reliability review by the ISO. If the ISO concludes that the unit submitting the de-list bid is needed for reliability purposes, the bid is rejected and the resource is retained.[163a]

Retirement works differently in traditionally regulated markets, such as in Colorado like Public Service of Colorado's service territory. As part of its decision-making under the Clean Air Clean Jobs Act, for example, Public Service of Colorado the company relied on its own dispatch models and reviewed options across its system to "take action," i.e., either to retire, control, or fuel switch a unit to natural gas. This was generally the case across the country before organized wholesale markets were established in the mid-1990s. Companies might pool their resources in a less formal manner, but generally speaking, there was no affirmative obligation to offer any particular unit for service. Instead, companies would have what was referred to in New England as a "capacity responsibility" and would have had to make a demonstration that they had sufficient capacity to meet their responsibility in the pool. In traditionally regulated markets, if the company wants is relatively free to retire a unit and replace it with another, the company does so, subject to reliability demands, and to any additional constraints that might be included in a generator's certificate of public convenience granted by a state commission.[163b]

In Xcel's analysis of Public Service of Colorado's system, the company determined that the existing transmission system and the units targeted for replacement posed distinct challenges for the company and dictated Xcel's "feasible" capacity replacement options. The capacity that was most suited for retirement (approximately 700 MW) was located in the Denver metro area (a significant load pocket), and the 230 and 115 kV transmission system serving the area was, in many respects, built around this capacity. So it was critical, were these plants to be retired, to maintain appropriate voltage and frequency on the transmission grid.

It is this additional reliability analysis that must occur at the local level, and at a level of detail that recognizes specific plants — generation that is being retired or retrofitted or is being brought on by new market entrants. The key focus in this effort is the location on the transmission system of each of the resources that may be affected.[164] As noted by PJM economist Paul M. Sotkiewicz, resource adequacy in the "global sense" is one thing, but where and when actual units may retire and new entrants actually appear is important to determine.[165]

163a. See ISO New England Inc. 5th Rev. Sheet No. 7308, FERC Electric Tariff No. 3, Section III – Market Rule 1 – Standard Market Design Tariff at Section III.13.2.5.2.5. "The capacity shall be deemed needed for reliability reasons if the absence of the capacity would result in the violation of any NERC or NPCC (or their successors) criteria, or ISO New England System Rules." Id.

163b In Vermont the certificate is a "certificate of public good." See, e.g., 30 V.S.A. Section 231(b). "A company subject to the general supervision of the public service board under section 203 of this title may not abandon or curtail any service subject to the jurisdiction of the board or abandon all or any part of its facilities if it would in doing so effect the abandonment, curtailment or impairment of the service, without first obtaining approval of the public service board, after notice and opportunity for hearing, and upon finding by the board that the abandonment or curtailment is consistent with the public interest…. provided, however, this section shall not apply to disconnection of service pursuant to valid tariffs or to rules adopted under section 209(b) and (c) of this title." Id.

164 This is a theme raised by PJM economist Paul M. Sotkiewicz in his presentation to the Bipartisan Policy Center on December 7, 2010. See "Thinking about Potential Reliability Consequences in PJM from Forthcoming EPA Rules" and comments of Paul M. Sotkiewicz, Ph.D., Chief Economist, PJM Interconnection, speaking at the Bipartisan Policy Center's "Environmental Regulation and Electric System Reliability, Workshop II: Reliability Impacts of Power Sector Developments," December 7, 2010 (Bipartisan Center, "Reliability Impacts"), http://www.bipartisanpolicy.org/news/multimedia/2010/12/10/reliability-impacts-power-sector-developments-power-sector-developments-a.

165 Id.

While the retirement of a small unit may not make much of a difference from a broader statistical perspective, from a transmission reliability point of view, it may make a significant difference.[166]

This again illustrates where demand response and energy efficiency may play a very important role. Both types of resources can be deployed quickly, and can be targeted geographically. If the economic decision is to retire a small, older generating unit, a premium value can be ascribed to distributed resources in the market and transmission area served by the retiring unit. So-called "efficiency power plants" have been developed in several regions of the world, and can often replace existing or new generation at considerable cost savings and emission reductions.[167]

Going forward then, as commissions assess the engagement of their utility companies on these issues, commissions will want to ensure that utilities develop and integrate relevant and current data regarding applicable health and environmental regulations, options regarding generation units that are candidates for action, emissions control strategies, replacement capacity, demand-side alternatives, and any specific transmission constraints or reliability challenges.

While state regulators have authority to affect rate-regulated utilities and their generation resource decisions, utility commissions do not have the same influence over decisions being made by merchant generators, especially vulnerable ones (for whatever reasons) whose retirement decisions could affect system reliability. As noted in the following section, the FERC and the EPA have indicated that they are attempting to work together to address, among other things, reliability implications of the EPA's forthcoming rules. The potential coordination between the EPA and the FERC was one of the subjects raised by recent inquiries of the FERC from Congress.[168] It is currently unclear what effect these inquiries will have on the possible development of a FERC/EPA relationship, joint agency solutions to reliability issues associated with merchant generation, and on the potential for producing least-cost solutions to the EPA's implementation of these public health and environmental regulations.

Developing Scenarios

After gathering current data on affected units, emissions control options and strategies, unit retirement and decommissioning alternatives, replacement generation, and transmission system reliability, companies can start to assemble scenarios for modeling that simulates future company actions.

In Colorado, the Act required Xcel to first examine a basic scenario referred to as the "benchmark" or "all controls" case that required the company to install NOx controls on all affected generation to achieve 70 to 80 percent reductions. This "starting point" scenario contained no flexibility to consider potentially less expensive options (e.g., fuel switching to natural gas).

The NERC Study, published in October 2010, relied upon a similar "all controls" approach for all the EPA rules: 316(b) (closed-cycle cooling), Mercury/Air Toxics (FGD/SCR/filter systems/activated charcoal injection), Clean Air Transport Rule (FGD/SCR), and Coal Combustion

166 Id. It should be noted that, on this topic M.J. Bradley wrote:

> [T]he retirement of some existing generating capacity will create room on the transmission grid to accommodate additional power flows, or new generating capacity, without requiring attendant upgrades in transmission, thus mitigating reliability concerns while reducing the cost of transitioning to a cleaner, more efficient generation fleet.
>
> M.J. Bradley at 5.

167 "Energy Efficiency Power Plants: A Policy Option for Climate-friendly Air Quality Management in China "Energy Efficiency Power Plants: A Policy Option for Climate-friendly Air Quality Management in China," http://www.raponline.org/docs/RAP_EPPandAirQualityinChina_2009_11_30.pdf; see also "China's Energy and Environmental Challenges, Committee on International Relations," Frederick Weston, NARUC Winter Meetings, 17 February 2008, http://www.google.com/search?q=weston+NARUC+china&ie=utf-8&oe=utf-8&aq=t&rls=org.mozilla:en-US:official&client=firefox-a.

168 On May 17, 2011, Senator Lisa Murkowski sent a letter to FERC Chairman Jon Wellinghoff expressing her concern over the possible effects of forthcoming EPA rules.

http://murkowski.senate.gov/public/?a=Files.Serve&File_id=88bd8af0-a3e3-4f98-82fd-2af961f312b0. On May 9, 2011 Congressmen Fred Upton, Ed Whitfield, and Cliff Stearns sent a letter to Steven Chu, the Secretary of the Department of Energy (DOE) and to FERC's Chairman Wellinghoff seeking, among other things, information on EPA coordination with DOE and FERC. http://republicans.energycommerce.house.gov/Media/file/Letters/112th/050911ChuandWellinghoff.pdf.

Residuals (various types of containment systems). The NERC Study applied the "all controls" assumption to determine compliance costs and resulting retirement or retrofit choices for generators nationwide. It retired generation units if its assumptions about compliance costs, fixed current O&M costs, and variable O&M costs (including cost of fuel) exceeded replacement costs. It retrofitted a unit if its costs were less than the costs of replacement power.

Beyond this benchmark scenario, Xcel also developed numerous combination scenarios. These included varied mixes of retirement, NOx controls, and fuel switches, and also different amounts of renewable resources (e.g., wind and solar) and demand-side management. Within each scenario, they also developed various portfolios of replacement capacity for possible retirements, and estimated potential portfolio costs through modeling.

Figure 12

Compliance for Existing Resources

Regulation	Timing-Development	Timing-Compliance
316(b)	Proposal March 2011 Final July 2012	8 years to install screens, nets, or to reduce intake velocity; 10 years (fossil units requiring cooling towers); and 15 years (nuclear plants requiring cooling towers.)
Mercury Air Toxics	Proposal March 2011 Final November 2011	3 years from final rule with possible 1-year extension
CATR	Proposed August 2010 Final June 2011	*Annual* SO_2 and NOx, Phase I Jan 2012; Phase II Jan 2014 *Seasonal* NOx Phase I May 2012; Phase II May 2014
CCR	Proposed June 2010 *Final TBD [169]	TBD

Feasible versus Conceivable

Of the many variables that can contribute to the development of a scenario, regulatory compliance deadlines, transmission/reliability concerns, and construction scheduling play a significant role. In Colorado, these limitations prescribed by the Act caused Xcel to conclude that not all of its "conceivable scenarios" would be "feasible scenarios." For example, the December 31, 2017 NOx reduction deadline under the Act had to be factored into each scenario. Schedules for facilities removal and replacement and controls installation had to fit within the December 2017 time frame, or else the scenario was rejected.

Compliance timelines set by EPA regulations should have a similar effect on companies as they develop scenarios. As noted in Fig. 12 while dates for final CCR and 316(b) regulations are uncertain, CATR and the Mercury/Air Toxics Rule will be finalized in June and November of 2011, respectively. CATR compliance will be phased. For annual SO_2 and NOx, Phase I compliance is expected in January 2012, and Phase II in January 2014. For seasonal NOx, Phase I compliance is expected in May 2012, and Phase II in May 2014. Existing sources under the Mercury/Air Toxics Rule are required to meet standards within three years of the publication of a final rule, with the possibility of a one year extension.

The analysis of additional transmission needs will be a critical part of scenario development. For a scenario to be deemed feasible, it must first pass the reliability test. Questions that will need answers include: where are plants located relative to load; how will reliability needs be met during retirement and construction periods; and what specific impacts will retirements have on voltage and frequency support?

All scenarios considered by Xcel had to ensure that the company could maintain reliability. Of the various scenarios that it developed addressing reliability requirements, the

169 The final rule deadline is likely to be revisited: "EPA Administrator Lisa Jackson had originally sought to issue a final rule in 2011 but she told a March 3, 2010 House Appropriations Committee interior panel hearing that a final rule is unlikely in 2011 given the work involved in processing more than 450,000 public comments on the proposed rule." "Inside EPA," April 5, 2011. http://insideepa.com/201104052359945/EPA-Daily-News/Daily-News/industry-says-epa-risk-assessment-fails-to-justify-strict-coal-ash-rule/menu-id-95.html.

company ultimately identified nine feasible scenarios. For each of these, Xcel identified multiple generation portfolios to replace retired capacity, causing the number of scenarios to grow quickly.[170]

The ability to schedule construction necessary for installing environmental controls will be a project-specific inquiry. Companies will need to consider this as they develop compliance scenarios. There are differing views about how an increase in demand for controls installation will affect the construction industry or the amount of constraint that it should place on potential scenarios. In its October 2010 study, NERC made assumptions about industry practices and industry's ability to meet compliance deadlines, noting that, "considerable operational challenges will exist in managing, coordinating, and scheduling an industry-wide environmental control retrofit effort will occur…."[171] As noted, NERC had not seen either of the proposed Mercury/Air Toxics or 316(b) rules when it issued its study; the EPA would not issue them for another 5 months. So it is not clear what NERC would conclude about the construction timelines implicated by the actual rules that the EPA proposed.

The Institute of Clean Air Companies (ICAC), articulates a more optimistic message about the ability of industry to meet the construction demands raised by the EPA's proposed regulations. David C. Foerter, Executive Director of ICAC, is very encouraging in his response to Senator Thomas Carper's inquiry as to whether or not "the availability of labor might constrain the industry as it seeks to comply with interstate transport [i.e., CATR] and utility MACT rules."[172] Foerter is confident in "the ability of . . . industry to deliver and satisfy … the labor, materials and resources needed to meet the demand."[173] According to Foerter, this is due to (1) over a decade of industry experience, (2) the "extent of controls already installed at existing coal-fired power plants," and (3) the availability of "less capital intensive control technology options available to the industry that can be implemented in a shorter period of time." He adds that currently the air pollution control industry "is in a period of underutilization as compared to the NOx SIP Call and CAIR Phase I years" (i.e., 2000-2010).[174]

Regardless of the precise degree to which the industry around the country will be able to respond to the construction demands necessary for installing environmental controls, it is important to recognize the potential for challenges associated with construction scheduling.[175] Given the actual implementation and compliance schedules adopted by the EPA and the precise control technologies that are chosen by particular resources (and whatever relevant construction industry information is available), this will be an important issue for regulators to monitor and for companies to model.

Numerous factors will be considered and be weighed differently among various companies as they consider the merits of various resources, strategies, and develop

170 Of the combinations of these options, the company identified one of these as its preferred scenario. CO PUC Docket No. 10M-245E, Decision No. C10-1328, December 9, 2010, Finding 56 at 23.

171 See EPA Scenario at V. NERC further notes that "compliance costs are based on current average retrofit costs with existing technology," and that the "assessment does not evaluate the compliance cost increases resulting from a run-up in labor and material costs caused by demand increase for environmental control and replacement power projects." Id. at 6, 9, and 49. To reflect this concern, NERC performed an additional sensitivity comparison for the 2015 Strict Case for MACT that goes beyond the Strict Case assumption of a 25 percent increase in cost for third-party engineering services to reflect potential for "compliance cost increases resulting from a run-up in labor and material costs caused by demand increase for environmental control and replacement power projects." Id. at 6, 9, and 49. See Figure 6: "Sensitivity of Retirements Plus Derated Capacity as a Function of Higher Assumed Costs due to MACT Regulation." It should be noted that NERC does not include estimates of lower cost strategies as alternatives to back-end compliance technology or reduced costs associated with resulting economies of scale resulting from greater use of certain compliance technologies.

172 Letter of Senator Thomas Carper to David Foerter, Executive Director, Institute of Clean Air Companies, October 6, 2010 (ICAC Letter).

173 Id. at 1.

174 Id. at 2.

175 See, e.g., comments of Steve Fine, Vice President, ICF International, in regard to 2000-2004 post SIP-call SCR installation costs, speaking at the Bipartisan Policy Center's "Environmental Regulation and Electric System Reliability, Workshop II: Reliability Impacts of Power Sector Developments," December 7, 2010 (Bipartisan Center, "Reliability Impacts"), http://www.bipartisanpolicy.org/news/multimedia/2010/12/10/reliability-impacts-power-sector-developments-power-sector-developments-a. It is not unusual for models to include a "congestion" function that recognizes some level of increase in construction activity and the associated potential for increased costs. See comments of Howard Gruenspecht, Deputy Administrator of EIA, regarding capability of EIA's NIMS model. Id.

176 Lazar at 73.

scenarios. As mentioned earlier, an optimal mix of resources is one that will be "cost-effective across a wide range of futures and sensitivity cases that also minimize the adverse environmental consequences associated with its execution."[176]

Modeling

Modeling allows a company to test the data it has developed and the various scenarios it has assembled. After putting together a set of feasible scenarios, companies can use their modeling capacity to determine costs of various scenarios implemented on their system. They can also develop a sense of how their system would react under various scenarios.

Relying on its own dispatch models, Xcel reviewed the company's ability to dispatch its own resources and purchased generation assets to meet its customer load. It used its models to represent both the existing system and least-cost generic resource techniques to represent what it considered would be the future system, including forecasts of energy, demand, fuel prices, and operations and maintenance costs

Xcel's modeling also looked at the economic dispatch implications of meeting load under each scenario. At the same time the modeling tracked numerous factors (e.g., fuel, O&M, capital, emissions costs, emissions levels, and total power supply system costs) and reported the present value of each of these costs within different time windows (e.g., 10 years, 20 years, 35 years).

Each scenario would report the present value of total power supply system costs. The shorter term (10 years) would be more certain and the longer terms (20 and 35 years) less so. These different views provide Xcel with a sense of the relationship between potential near-term and longer-term costs and benefits.

Sensitivities

In developing sensitivities, a modeler revisits certain assumptions already modeled and recasts them to see how sensitive the results are to changes in the specific assumptions. For example, one of Xcel's sensitivities assumed and modeled higher construction costs than originally considered. Xcel also revisited assumptions about fuel prices, CO_2 costs, replacement generation costs, and additional renewable resource and demand-side management investments.

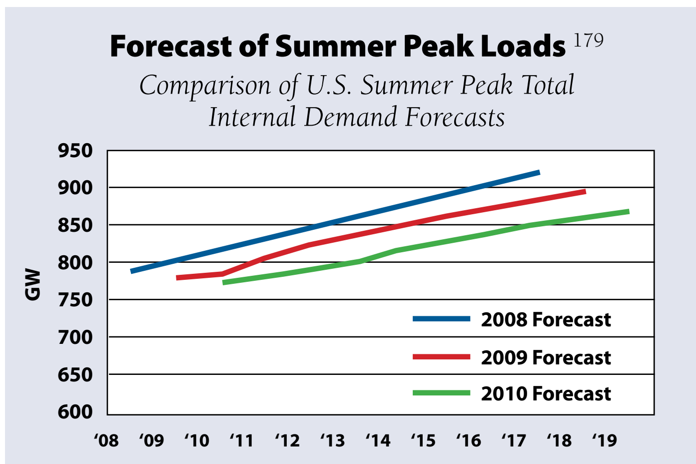
Sensitivities can also be used to update assumptions based on the availability of more current information. For example, NERC's Study utilized used data from its own *2009 Long-Term Reliability Assessment* (2009 LTRA) rather than its *2010 Long-Term Reliability Assessment* (2010 LTRA). In the more recent NERC report, electricity generation capacity numbers were higher than those relied upon in its *EPA Scenario*. The 2010 LTRA's total U.S. "Existing Certain & Net Firm Transactions" (932,071 MW) exceed the same figures from the 2009 LTRA (925,336 MW) by 6,735 MW.[177]

Similarly, in the 2010 LTRA, NERC's more recent demand numbers are lower than those relied upon in the NERC Study. As demonstrated in Fig. 13 projected future summer loads, for example, are significantly lower than anticipated in earlier forecasts:

> *A comparison for 2018, the last common year of the two projections, shows that the summer peak demand for the United States is 36,400 MW (or about 4.1 percent) lower than last year's projection. Furthermore, when comparing this year's forecast with the 2008 forecast (pre-recession), the 2017 peak demand forecast is 71,400 MW (or 7.8 percent) less, representing a significant decrease over the past two years.*[178]

This is not to say that NERC should have used its newer data; NERC had to plan this study and conduct it with available (i.e., 2009) data. In both of these instances,

Figure 13



177 NERC 2009 LTRA at 397; 2010 LTRA at 30.

178 2010 LTRA at 5; see also Fig. 3.

179 Id.

however, the supply and demand numbers varied considerably and the effects that they have on the modeling assumptions can likewise be significant. Because Planning Reserve Margins are a measure of “the amount of generation capacity available to meet expected demand in the planning horizon,” regulators should note that, all things being equal, had NERC used its own more recent supply and demand data in its *EPA Scenario,* the resulting reserve margins would have been greater and the potential resource adequacy challenge less pronounced.

Another value in conducting sensitivities lies in the ability to test how robust a given scenario is under various futures. For example, it is not clear what effects increased demand for gas will have on supply and demand for non-gas generation. Increased demand for gas could increase the difference between gas and coal prices, which might benefit remaining coal-fired generation and change the retirement economics. In order to test this, a company might revisit coal and gas prices and run sensitivities on them.

Part Three
Potential Next Steps for Commissions

In order to better understand forthcoming EPA regulations and the implications of implementation locally, utility commissions should take the opportunity to explore these and related issues with others, including utility companies, sister state energy and environmental agencies, and federal agencies like the EPA and the FERC.

In fact, commissions may want to consider explicit collaborations with their counterparts in state environmental agencies. These may be informal meetings between staff or commissioners that are general and introductory or more in-depth and topic-focused. For example, energy regulators and environmental regulators use significantly different terminology in their respective processes. An effort to clarify some of these differences (e.g., as a side event at other established meetings) might provide a simple starting point for the development of productive conversations between state energy and environmental regulators. This same approach might be useful with representatives from regional EPA offices and with representatives from commissions in adjacent states, particularly where multi-state utilities and jointly-owned power plants serve adjacent jurisdictions or where there are close inter-state interconnections in power markets.

Meetings might also attempt to go into more depth on the challenges associated with greater coordination between environmental and energy regulators. For example, a better understanding of "State Implementation Plans," (SIPs) a key regulatory tool used by state air regulators, or potential connections between SIPs and utility planning would be useful for utility commissions trying to understand effects of forthcoming EPA regulations.[180] There may be additional approaches for devising solutions across related emissions sources (e.g., "bubbling" of emissions sources under CATR) or possible regional solutions. While air regulators may only be able to address specific pollutant emissions from individual power plants, for instance, utility regulators can guide the expansion of energy efficiency and demand response programs that reduce emissions of multiple pollutants by reducing the underlying load that needs to be served.

In fact, such "multi-pollutant" strategies provide another constellation of issues that commissions could explore with environmental regulators. The general question would be whether there are opportunities for coordination between regulatory programs that might implicate cheaper overall compliance strategies for companies. For example, because certain compliance technologies address more than one pollutant, would it be worth examining the costs and benefits of Mercury/Air Toxics Rule compliance and their relationship with CATR compliance?[181] This type of inquiry could implicate existing regulatory timelines and judgments as to the reasonableness of company investment strategies.

Commissions and environmental regulators could

180 Key principles for air quality planning include:

- Long-term (10-15 years) planning period;
- Integrated air quality modeling and monitoring;
- Monitoring data are part of inputs to air quality models;
- Emissions reductions necessary to attain and maintain the air quality standard;
- Process consistency;
- Quantifiable, enforceable emissions reductions; and
- Effective program oversight.

181 Another example might call for the consideration of compliance issues in the long term and their implications on compliance investment today. For example, in modeling conducted for its recent study, "A Reliability Assessment of EPA's Proposed Transport Rule and Forthcoming Utility MACT," Charles River Associates took a more stringent approach than NERC and others who have modeled CATR NOx requirements. Rather than adopting the relatively relaxed NOx standards from CATR, Charles River Associates chose to model effects of the current NOx standards in the Clean Air Interstate Rule as a proxy for the likely more stringent NOx standards that may be proposed under CATR II.

also jointly convene face-to-face meetings with key stakeholders, including utilities, independent generators, the energy efficiency industry, and others to gauge likely utility exposure to upcoming regulations and utility preparedness in light of these challenges. Many questions could be addressed as affected parties educate themselves about forthcoming federal/state requirements, as well as each other's expectations, needs, and constraints.

Such meetings could help regulators and companies identify the many general and local issues that are likely to present themselves in the near future. These meetings would also be an opportunity to signal utilities that proactive planning provides the potential for greater choice of compliance alternatives and the potential for lower cost compliance. This would also be an opportunity for companies to gain the support of their energy and environmental regulatory commissions as they move forward.

In requiring the inclusion of "non-transmission solutions" in planning processes, FERC has opened the door for a broader review of alternatives in transmission planning, thereby creating the opportunity to include potentially less expensive measures, and potentially cleaner resources that could help states with environmental compliance challenges.

Commissions may also want to explore working with federal agencies whose programs may be of assistance to state commissions attempting to sort out these challenges. For example, in 2010 FERC released its "Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities" Notice of Proposed Rulemaking (NOPR) in which it recognized that:

> *[G]reater regional coordination in transmission planning would expand opportunities for transmission providers, their transmission customers, and other stakeholders to identify and implement regional solutions to local and regional needs that are more cost-effective than those proposed in the transmission planning process of individual transmission providers.*[182]

In the NOPR, FERC proposed a requirement for a "regional transmission planning process [to] consider and evaluate transmission facilities and other non-transmission solutions that may be proposed and develop a regional transmission plan that identifies the transmission facilities that cost-effectively meet … needs."[183] FERC proposed to require both individual transmission providers engaged in local planning as well as regional planning processes to consider "transmission facilities and non-transmission solutions" as part of planning processes.

In requiring the inclusion of "non-transmission solutions" in planning processes, FERC has opened the door for a broader review of alternatives in transmission planning, thereby creating the opportunity to include potentially less expensive measures and potentially cleaner resources that could help states with environmental compliance challenges.

As states develop their understanding of the role of clean energy solutions in meeting the requirements of forthcoming EPA health and environmental regulations, they may want to explore the implications of FERC's interest in promoting non-transmission alternatives as part of regional system planning.

As noted earlier, States may also want to explore the possibility of FERC and EPA developing a joint response to potential reliability challenges associated with possible unit retirements due to the combination of market effects and the effects of EPA regulations on older, smaller, dirtier, and/or economically marginal generation. The EPA and FERC have indicated their intent to model potential effects on electric generation associated with the EPA's forthcoming regulations,[184] but part of that effort might include the development of a mechanism to enable early identification of threats to system reliability associated with potential retirements of generation units. State involvement could also help focus follow-up modeling efforts to optimally address such threats once identified.

Because FERC (through NERC) has authority over system reliability, it could develop a joint protocol with the EPA to address reliability concerns. Under such a protocol, if the EPA were to issue a rule affecting the power sector,

182 FERC NOPR RM10-23-000 (June 17, 2010) at Paras. 51-52.

183 Id. "Non-transmission solutions" include energy efficiency, demand response, distributed resources, fuel switching, and load-center generation.

184 See http://energywashington.com/ The data developed in this process could be valuable as the states go forward with their own inquiries.

utilities or RTOs might have a certain amount of time to indicate whether or not there were actual reliability concerns associated with the rule, and specifically, what aspects of the rule put which plants at risk. Once utilities and RTOs had identified the plants and regions or areas potentially affected and provided supporting information, then FERC could review and verify the claims.

In cases where FERC determines that there could be a genuine reliability issue, the RTO or utility would engage in a process to find substitutes that would address the reliability challenge within a reasonable time, but no later than the timeframe for implementation of the rule itself. The EPA's pending rules, driven by statutory deadlines and judicially derived settlement agreements, provide dates by which generators need to be in compliance. Such a process would be similar to the ones already in place around the country for granting "reliability-must-run" or "RMR" status to generators that would otherwise have to withdraw from the market due to economics.

Conclusions

The EPA's current development of public health and environmental rules will have a significant impact on the electric sector. Due to the extensive reach of environmental regulations, energy regulators will need to work more closely with environmental regulators as utility resource planning decisions are explored. Never before has building understanding between utility commissions and their sister regulatory agencies been so important. By engaging with utilities and with other regulators, utility commissions will be better suited to evaluate a wider array of potential futures, thereby identifying the most affordable compliance scenarios associated with various EPA public health and environmental regulations.

Appendix 1
Acronym Glossary

BACT Best Available Control Technology
BTA Best Technology Available
CO_2 Carbon Dioxide
CO_2e Carbon Dioxide Equivalent
CAIR Clean Air Interstate Rule
CATR Clean Air Transport Rule
CCR Coal Combustion Residuals
CDPHE Colorado Department of Public Health and Environment
CEMS Continuous Emissions Monitoring System
CHP Combined Heat and Power
DR Demand Response
DSI Dry Sorbent Injection
EPA US Environmental Protection Agency
ESP Electrostatic Precipitator
FERC US Federal Energy Regulatory Commission
FGD Flue gas desulfurization
FIP Federal Implementation Plan (see SIP)
GW Gigawatt
GHG Greenhouse Gases
HAP Hazardous Air Pollutants
Hg Mercury
IB Illinois Basin
ICAC Institute of Clean Air Companies
INGAA Interstate Natural Gas Association of America
IPM Integrated Planning Model
MACT Maximum Achievable Control Technology
MW Megawatt
NAAQS National Ambient Air Quality Standards
NAP Northern Appalachian
NARUC National Association of Regulatory Utility Commissioners
NCEP National Commission on Energy Policy
NERC North American Electric Reliability Corporation
NOPR Notice of Proposed Rulemaking
NOx Nitrogen Oxide
NPDES National Pollutant Discharge Elimination System
NSPS New Source Performance Standards
NSR New Source Review
O&M Operations and Maintenance
PM Particulate Matter
PRB Powder River Basin
PSD Prevention of Significant Deterioration
PTE Potential to Emit
RCRA Resource Conservation and Recovery Act
RMR Reliability-Must-Run
SCR Selected Catalytic Reduction
SIP State Implementation Plan
SNCR Selective Non-Catalytic Reduction
SO_2 Sulfur Dioxide
TL Texas Lignite
UARG Utility Air Regulatory Group
WB Western Bituminous
ZLD Zero Liquid Discharge

Appendix 2

Controls for Criteria and Toxic Air Pollutants[185]

While some emissions control technology is related to the pre-combustion phase of energy production, most control technology is directed at the combustion and post-combustion phases of energy production. Pre-combustion technologies include products referred to as "engineered fuels" that can have reduced sulfur dioxide (SO_2), spell out like the others (NOx), mercury, and carbon dioxide (CO_2) content and therefore, associated emissions. These fuels include coal "preparation" (cleaning), upgrading (dewatering with heat and/or microwaves), and treatment with additives to alter combustion characteristics. Combustion and post combustion technologies include scrubbers, selective catalytic and non-catalytic reduction, and electrostatic precipitators.

SO_2 and Acid Gas Removal

"Scrubber" is a general term that describes an "air pollution control device or system that uses absorption, both physical and chemical, to remove pollutants from the process gas stream." Scrubbers are also known as flue gas desulfurization or "FGD" systems. They rely upon a chemical reaction between pollutants such as SO_2, acid gases, and other air toxics from flue gases. These systems can be classified as either "wet" or "dry" but both systems employ significant amounts of water in their processes.

In a "wet" scrubber, a liquid sorbent (i.e., absorbing material) is sprayed into the flue gas. Wet scrubber technology can be used in absorbing gases and particulate matter. In the case of SO_2 removal, for example, calcium is used as a sorbent. This reacts with the SO_2, forming into a wet, solid waste by-product that can require additional treatment. New wet scrubbers can achieve SO_2 removal efficiencies of upwards of 90 percent. Scrubbers have been used on coal-fired boilers, significant sources of hydrochloric acid (HCl) and hydrofluoric acid (HF), with removal efficiencies for HCl in the 90 percent range, and HF by more than one-third. Wet scrubbers also help remove arsenic, beryllium, cadmium, chromium, lead, manganese, and mercury from flue gas.

In a "dry" scrubber or FGD process, sorbents are injected in flue gas, producing a dry solid by-product. There are various types of dry scrubbers, but all typically introduce an absorbing material at some point in the combustion process which reacts with the pollutant. The resulting materials, including fly ash, are generally collected downstream in particulate control devices, e.g., an electrostatic precipitator or fabric filter (discussed below).

NOx Removal

Selective Catalytic Reduction (SCR)

SCR is a process for controlling nitrogen oxide (NOx) emissions by reducing NOx to liquid nitrogen (N_2) and water (H_2O) by the reaction of NOx and ammonia (NH_3) in the presence of a catalyst. The process occurs at controlled temperatures within a "reactor" chamber made of certain types of metal, e.g., titanium or platinum. SCR technology can provide reductions in NOx emissions in the 90 percent range.

Selective Non-Catalytic Reduction (SNCR)

SNCR relies on a chemical process and high temperatures that changes NOx to N_2 similar to SCR, but

185 Based on information found at "Pre-Combustion Technologies: A Key Environmental Compliance Tool," Jason Hayes "Power," Februrary 1, 2011, http://www.powermag.com/coal/Pre-Combustion-Technologies-A-Key-Environmental-Compliance-Tool_3401_p2.html; "Acid Gas/SO2 Control Technologies," "NOx Controls Technologies," and Particulate Controls, ICAC, http://www.icac.com/i4a/pages/index.cfm?pageid=3398; Maxon Corporation, https://www.maxoncorp.com/Pages/product-Low-Nox-Burners; for additional information on cost of environmental controls, see "Environmental control costs and the WECC Fleet—Estimating the forward-going economic merit of coal-fired power plants in the West with new environmental controls," Synapse Energy Economics, Inc. Jeremy Fisher, Bruce Biewald, January 23, 2011.

without the use of a catalyst. Typically, ammonia or another "reagent" is introduced into hot flue gas under controlled temperatures and converts the NOx into nitrogen gas and water vapor. The process is referred to as "selective" because it reacts with (i.e., "selects") NOx and does not react with other constituents of flue gas. SNCR is significantly less effective than SCR, but under optimal conditions can reduce NOx levels by as much as 75 percent.

Particulate Removal

Electrostatic Precipitators

An electrostatic precipitator (ESP) uses an electric field to remove particulate matter from flue gas. An ESP creates an electric field that charges particles negatively. These particles pass through "collecting electrodes" that attract them. Electrodes are periodically shaken, dislodging particulate matter that falls into disposal containers.

Fabric Filters

Fabric-filter collectors — also known as "baghouses" — work like sieves. Flue gas passes through tightly woven fabric which catches particulate matter. Fabric filters are capable of 90 percent removal efficiencies over a range of particle size.

Wet Scrubbers and Mechanical Collectors

Particulates can be removed with wet scrubbers and mechanical collectors. Wet scrubbers remove particles found in liquid droplets. Wet scrubbers have removal efficiencies in the 90 percent range for particles larger than 10 microns in diameter. Efficiencies are much lower for smaller particles. Mechanical force can also be used to collect particulate matter more effectively with larger particulates than with smaller (i.e., particles in the range of 2.5 microns in diameter or "PM2.5").

The Regulatory Assistance Project (RAP) is a global, non-profit team of experts focused on the long-term economic and environmental sustainability of the power and natural gas sectors. We provide technical and policy assistance on regulatory and market policies that promote economic efficiency, environmental protection, system reliability and the fair allocation of system benefits among consumers. We have worked extensively in the US since 1992 and in China since 1999. We added programs and offices in the European Union in 2009 and plan to offer similar services in India in the near future.
Visit our website at **www.raponline.org** to learn more about our work.

RAP

HOME OFFICE (US)
50 State Street, Suite 3
Montpelier, Vermont 05602
phone: +1 802-223-8199
fax: +1 802-223-8172

EU OFFICE
48 Rue de Stassart
Building C, BE-1050
Brussels, Belgium
phone: +32 2-894-9300
fax: +32 2-894-9301

www.raponline.org