The Future of U.S. Climate Policy: Coal, Carbon Markets, and the Clean Air Act

October 28, 0214

CLE Materials: Implementation Challenges & Opportunities

- *Walking the Line Between the Clean Air Act and the Federal Power Act: Balancing Emission Reductions and Bulk Power Reliability*
  Michael Gergen, Claudia O'Brien, Eli W.L. Hopson and David E. Pettit: The Electricity Journal
  2012

- *A Roadmap for State Comments on the Clean Power Plan*
  Megan Herzog: Legal Planet
  September 17, 2014

- *Issue Brief: The Electricity System and Implications for Federal Carbon Pollution Standards*
  Tom Curry and Austin Whitman: Georgetown Climate Center
  May 2014

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MEGAN HERZOG September 17, 2014

A Roadmap for State Comments on the Clean Power Plan

Considerations for State Regulators Tackling EPA's §111(d) Proposed Rule

"Dear EPA…"

Yesterday, EPA announced its decision to extend the comment period on the Clean Power Plan—the agency's proposed rule to regulate power plant greenhouse gas (GHG) emissions under Clean Air Act § 111(d)—until **December 1, 2014**. The comment period was originally scheduled to last 120 days, until October 16th. **You can find a list of compiled resources and background information on the Clean Power Plan here.**

Stakeholders may see EPA's comment deadline extension as either a blessing or a curse. On one hand, most of us are still trying to unpack the hundreds of pages of rule text and technical support documents. On the other hand, given the breadth, length, and complexity of the proposal, we could hold hearings and seminars until judgment day and still have issues left to discuss. Not to mention that the Monday deadline means many poor lawyers will be finalizing comments over the Thanksgiving holiday. (Ask mom to set aside a slice of pie for your staff attorney.)

I view the comment deadline extension as a positive development for the state regulators who are positioned to do much of the heavy lifting to gather relevant data, coordinate relevant entities, and communicate with EPA about gaps in the proposal.

What exactly should states be doing between now and December 1st as they prepare their comments to EPA? It just so happens that I was asked to speak about this very topic today as a panelist on a National Regulatory Research Institute (NRRI) teleseminar. I share a version of my presentation here in the form of a roadmap for state comments on the Clean Power Plan. First, I outline a few useful, informative things you, state regulators, can do in advance of sitting down to draft comments to help you think about what the proposed rule means for your state. Then, I present several substantive issues you may wish to consider as you develop your comments.

1. **Adopt the appropriate commenting mindset.**

It is important to emphasize that the proposed rulemaking is just an early step in the regulatory process. EPA set forth a variety of regulatory alternatives and open questions for comment. The contours of the rule remain unsettled. Ultimately, the final rule (expected June 2015) could look very different from this proposal. No doubt EPA will receive an extraordinarily large volume of comments, and the agency may materially alter the content of the rule in the course of responding to comments and preparing the final rulemaking.

If there is anything you would like to see in the final rule that is not in the proposal, or any challenges you or the stakeholders in your state see with the proposed rule, now is a good time to flag these issues and begin a conversation with EPA. *EPA is actively seeking feedback and wants to hear from states about the proposal, including suggestions of which legal design options to adopt and what additional guidance to include in the final rule.*

2. **Consult with other relevant public entities**.

Your state air pollution regulator is responsible for submitting the state plan and likely will play a key role in determining your state's emission reduction pathway—but not the only role. Other entities may be essential for federal compliance or simply beneficial to include in this process because they have relevant information or expertise, or play a role in implementing relevant emission reduction programs. A few entities you may want to consider consulting include:

- air pollution control agency,
- state energy agency/office,
- public utilities commission,
- department of natural resources,
- governor's office,
- consumer/ratepayer advocate, and
- utility representatives.

As an example of interagency collaboration, Colorado's energy agencies have a weekly standing call to discuss issues related to the Clean Power Plan. In the course of your consultations, you might consider whether it makes sense to develop joint state agency comments.

3. **Consult with stakeholders.**

You may want to hold a public meeting and/or request formal or informal input from stakeholders such as:

- utilities (IOUs, POUs, cooperatives),
- utility associations,
- environmental groups,
- renewable energy developers, and
- major electricity customers.

States have utilized a variety of methods to engage with stakeholders to date. As a few examples:

- California's energy agencies recently held a joint public meeting guided by a discussion document that outlined some of the key questions and considerations on which the energy agencies sought feedback.
- Iowa's Department of Natural Resources is holding a series of meetings allotting each stakeholder a few minutes to share an overview of the comments it plans to provide to EPA.
- Arkansas' Department of Environmental Quality and Public Service Commission host a 111(d) Stakeholder Workgroup to share information and discuss options for the Arkansas plan.

4. **Inventory existing "outside the fenceline" policies and programs; consider how they mesh with the proposed rule; identify implementing entities.**

Begin taking inventory of any existing "outside the fenceline" state energy and environmental policies and programs that are relevant to reducing the carbon intensity of your state's electricity sector. A few examples include:

- RPS,
- energy efficiency standards,
- renewable energy incentive programs,
- integrated resource plans,
- ISO/RTO demand response protocols,
- voluntary standards,
- loading orders,
- smart metering programs,
- planned transmission upgrades,
- building energy codes, and
- any energy efficiency measures already in SIPs to achieve NAAQS.

Keep in mind that many of these programs may be administered by entities other than air pollution control regulators. It may be beneficial to consult with these entities. Consider also how well existing state programs harmonize with the proposed rule. For example, the scope of a state policy may be broader or narrower than the electricity sector, or its compliance timeframe might differ from that of the Clean Power Plan.

5. **Do some rough unit- and system-level baselining.**

Comparing the 2030 target to the 2012 baseline is not sufficient to understand the impact of the rule. The electricity sector in every state will undergo major transformations between now and 2030 even absent the Clean Power Plan—and EPA largely ignored these dynamic changes when it calculated the state targets. Understanding roughly where your state's electricity sector will be in terms of carbon intensity by 2030 under a "business as usual" scenario is essential. It may be challenging to model the state's energy system exactly according to the parameters of the Clean Power Plan, but do what you can with existing tools and capacity to get a basic picture.

Some specific things you might want to inventory include:

- planned power plant repowering projects,
- expected divestments and retirements,
- impacts of existing energy efficiency and renewable energy programs
- in-state and out-of-state facilities supplying electricity to customers in your state,
- unit-level GHG emission data (EPA has a mandatory emissions reporting rule for large GHG sources; your state also may have a GHG emission inventory).
- future load projections (including any electrification increases associated with electrified transportation),
- top electricity users and top GHG emitters in your state,
- known "inside the fenceline" emission reduction opportunities, and
- state/regional renewable energy and energy efficiency potential studies.

All of this information can inform your state comments. Once you have a basic understanding of your state's baseline emission trajectory and strategies that have reduced emissions in the past or are projected to reduce future emissions, you can think about where your state stands in relation to the following substantive issues.

1. **Interstate Collaboration**

While the Clean Power Plan does not require interstate collaboration, it supports and encourages regional and multistate approaches. There has been much discussion of the fact that the default state-by-state structure of the Clean Power Plan is complicated by electricity import/export relationships on the ground. For example, here in West, there are many long-distance electricity transfers across state lines. In some regions, RTOs play a major role in dictating how a state's generation is dispatched to a regional grid.

The proposal envisions that states can account for these and other cross-state impacts through multistate partnerships. For example, states can establish an agreed-upon accounting methodology for emission reductions associated with renewable energy and energy efficiency investments. States may want to comment on whether the rule properly recognizes import/export relationships and the interconnected nature of the grid, ensures that credit for emission reduction investments is distributed to the appropriate state without double-counting, and adequately supports and facilitates multistate partnerships that would improve compliance efficiency in your state.

Some issues to consider:

- **Would a regional approach make sense for your state?** What are the regional import/export and transmission dynamics? What states fall into the footprint of your RTO/ISO? Do you already participate in a relevant interstate partnership (e.g., the Regional Greenhouse Gas Initiative (RGGI) or Pacific Coast Collaborative)? With which states might you partner?
- **What forms of interstate collaboration might be best?** Begin evaluating the potential challenges and opportunities of different design options (e.g., multistate plans designed to achieve a multistate target, MOUs, state-specific plans that include common plan elements, such as a common accounting system). Take inventory of any existing interstate agreements, and think about how they might serve as a legal design model.
- **What tools could be helpful to account for cross-state impacts?** Take stock of tools that currently facilitate interstate collaboration in the electricity sector (e.g., the Western Renewable Energy Generation Information System (WREGIS), which creates renewable energy certificates for states in the Western Electricity Coordinating Council).
- **Given competitive market dynamics and interstate grid dynamics, what actions could other states take that could impact your state's compliance?** Could interstate agreements help address these issues?
- **What types of accounting rules/federal guidance would support regional collaboration?** There may be interstate conflicts over credit for emission reductions, and the interstate nature of the grid raises the possibility of double-counting. EPA seeks comment on how, if at all, it may be able to allow states to take credit for out-of-state emission reductions resulting from energy efficiency programs while avoiding double-

counting. What guidance regarding legal responsibilities and emission reduction measurement would facilitate interstate agreements with your desired partners?
- **Should EPA develop multi-state goals that track RTO/ISO footprints?**
- **How should multi-state goals be calculated?** For states submitting a multi-state plan, EPA declares that individual state goals would be replaced with a multi-state goal. How should multi-state goal calculation differ from individual state goal calculation?

2. **Rate-Based vs. Mass-Based Targets.**

The proposal would give states the option to use as a compliance standard either the EPA-issued rate-based target (lbs CO_2/MWh) or a mass-based goal (tons CO_2/state/yr). A state opting to use a mass-based target must describe the process used to calculate the target.

Some issues to consider:

- **What type of target might make sense for your state?** Which might provide greatest flexibility for the state? What are the pros and cons of each (e.g., some states, such as California, have climate mitigation programs that are already pegged to a mass-based target)?
- **What guidance would you want from EPA about converting from a rate-based to a mass-based target?** In practice, the process of converting between rate-based and mass-based targets is complex. EPA is seeking comment on how to calculate mass-based goals, and what form of guidance to provide to states about the calculation process.
- **Is there an advantage to working with states that adopt the same compliance metric?**

3. **Evaluating, Measuring, Verifying, and Reporting (EMV&R) Emission Reductions**.

Emission reductions associated with "outside the fenceline" emission reduction strategies need to be accurately evaluated, measured, and verified so that states can count them toward compliance. Your state may need additional tools to calculate the emission reductions associated with measures such as appliance standards and building codes that are not typically subject to regulatory EMV. At the same time, your state may want to balance its desire for clear guidance with its desires to retain autonomy to innovate in state policies and to reduce unnecessary procedural hassles.

Some issues to consider:

- **Evaluate existing EMV tools.** Your state may already use certain EMV protocols.

Your regulatory agencies may have their own methodologies, or interstate coordinating bodies may require specific protocols. As a first step, you can investigate the utility of existing EMV tools and think about whether they could serve as a model for EMV in this context.

- **What additional guidance does your state want from EPA about EMV** that is not already in the rule and technical support documents?
- **What would you want to see in federal interagency guidance regarding EMV?** EPA states in the proposal that the agency intends to develop, in concert with other federal agencies, new guidance specific to the EMV of renewable energy and demand-side energy efficiency programs for the purposes of state plans.

4. **Federal Approval Requirements and "Enforceability."**

EPA's proposal reiterates the statutory requirement that state plans must include "enforceable" measures that reduce EGU emissions. Typically, enforceable measures include things like state statutes, state regulations, or state PUC orders. By virtue of their inclusion in a state plan, enforceable state measures are federally enforceable.

In the context of the Clean Power Plan, enforceability raises concerns about expanding federal presence into areas that are traditionally the province of state regulators. States have an interest in ensuring that state cap-and-trade, renewable energy, and energy efficiency programs can be used to comply with the Clean Power Plan while retaining state flexibility and autonomy over these policies, and with minimal procedural hassle.

EPA seeks comment on specific open questions related to enforceability, including: **1)** whether EGUs must be held accountable for implementing renewable energy and energy efficiency measures, or whether other entities, such as the state itself, can be responsible; and **2)** whether inclusion in a state plan renders such measures federally enforceable. Notably, nothing in the Clean Air Act prohibits states from including other stuff in state plans in addition to enforceable measures.

In the proposal, EPA set forth several approaches to state plans that could avoid rendering all state emission reduction programs federally enforceable.

<u>Some issues to consider:</u>

- **What enforceability method would be best for your state?** Ideally, what would the state like to put forth as the federally enforceable component of its plan? Which state programs would the state prefer not be federally enforceable? Would it benefit the state to commit to achieving emission reductions without making its emission reduction programs themselves federally enforceable, as some states (e.g., California, Texas, and New York) do in their SIPs under Clean Air Act § 110?

- **How can the state show that is chosen strategy will achieve the required emission reductions?** What types of data would the state need to report to show compliance? Does the state already collect this data from its facilities?

5. **State Goal Calculation.**

Some environmental groups have criticized EPA for not setting more ambitious state targets. Some industry groups and states have criticized EPA for adopting overly aggressive targets. EPA writes in the Clean Power Plan that it aimed to calculate "reasonable rather than maximum possible" state targets so as to allow for state flexibility. EPA made a number of general assumptions in calculating the four building blocks that went into development of the state target (e.g., projected demand growth, energy mix, cost-effectiveness of RE/EE). EPA made some of these assumptions on a state-by-state basis, others on a national or regional basis. States may wish to comment on whether the state targets *strike the correct balance between stringency, so as to ensure national carbon emission reductions, and state compliance flexibility*.

Some issues to consider:

- **Could EPA's target calculation methodology be improved?** How would improvements affect your state's target? Other states' targets?

***The Clean Power Plan is complex, and there are obviously more issues to consider than I have listed here. These are simply a few of the "big-ticket" issues for states. Other LegalPlanet posts lay out additional questions worthy of consideration. The LegalPlanet Team will continue to post analysis about the proposal. In the meantime,* happy commenting!**

111(d), Climate Change, Federal Climate Policy, Greenhouse gas emissions, public comments, state climate policy

Issue Brief: The Electricity System and Implications for Federal Carbon Pollution Standards

Tom Curry and Austin Whitman, M.J. Bradley & Associates LLC

Executive Summary

The U.S. Environmental Protection Agency is currently developing regulations for carbon pollution from existing power plants under Section 111(d) of the Clean Air Act (CAA). [1] As state environmental agencies develop plans in response to EPA guidelines, coordination with state and regional electricity system regulators will be important. While the language of Section 111(d) contemplates state programs, electricity flows across state lines, and in large parts of the country it is managed through multi-state electricity markets that do not align with state borders.

This paper provides a brief primer on the electricity system and the role played by different entities in its operation and oversight, and identifies key issues that will be relevant for states to consider as they develop plans under Section 111(d).

The paper covers three topics:

- ***Principles of Electricity Supply***. Most electricity consumers in the U.S. are connected to a multi-state electric grid. Because electricity cannot be stored, the electricity system must be kept balanced in real time, and this frequently requires drawing power from generators in multiple states. Interstate electricity flows and resource availability will be important considerations in the development of Section 111(d) compliance plans.
- ***Resource Adequacy Planning.*** Many local, state, and regional entities coordinate to ensure power reliability. As environmental regulators work to design and implement Section 111(d) compliance plans, potential impacts of those plans on electric supply will be reviewed by planners, regulators, and stakeholders. Integration and alignment with existing processes for maintaining resource adequacy will be important during Section 111(d) planning.
- ***Scheduling, System Control, and Dispatch.*** Electricity markets already incorporate many environmental costs through established operating rules and practices. Environmental regulators may want to consider strategies, such as multi-state agreements, that take advantage of these existing tools. Understanding how different Section 111(d) strategies might affect electricity markets can help environmental regulators optimize environmental performance and cost-effectiveness.

The introduction of Section 111(d) standards will require collaboration and planning, but many of the regulatory and market processes that could underpin a sound approach to carbon pollution reduction policies can already be found in practice.

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[1] President Barack Obama, Presidential Memorandum – Power Sector Carbon Pollution Standards (June 25, 2013), http://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards.

1. Introduction

Over the past 125 years the U.S. power grid has grown across physical and political boundaries to bring electricity from power plants to customers reliably and economically. Spanning roughly 600,000 miles of wires and 18,000 generating units, and serving hundreds of millions of people, the system is a complex and dynamic organism. It is overseen by many organizations whose roles vary from city to city and state to state, each with a designated role in overseeing planning and operations.

To the outside observer, the operations of the electricity system are mainly visible when it fails. That blackouts happen so infrequently is the result of complex planning and operational processes that address potential issues over time spans ranging from decades to milliseconds. System planners have the ability to adjust their resource plans and market rules to take into account aging infrastructure, new technologies, public policies, and other factors.

Environmental standards are commonplace. Every electricity planning area in the country has its own energy mix and its own strategy for complying with air, water, and other regulations. Taken together, the key players in the electric sector have significant experience incorporating air quality targets, emission performance standards, emission caps, and other environmental policy inputs into electricity planning.

2. Principles of Electricity Supply

The inability to store electricity cost-effectively and at large scale creates a need to balance the electricity system in real-time. Grid operators must match supply to ever-changing demand, often covering multiple states at once. Several principles of electricity supply will be important in considering potential Section 111(d) compliance strategies.

Reliability

Reliability is a critical priority for every electricity system operator, and is measured in two ways. First is adequacy: the system needs to have adequate generating capacity to meet the needs of consumers at all times. Second is security, the ability of the system to withstand sudden disturbances. Reliability is an essential element of any planning strategy and is a prerequisite to success when it comes to changes in electricity system policies.

Extensive Interstate Trade

As a result of ever-changing consumption, electricity flows where it is needed. One minute, the output from a nuclear power plant and a coal-fired plant in Pennsylvania may commingle and power the streetlights of Scranton. The next minute, as people wake up and a factory begins operations, a natural gas-fired plant across the river in New Jersey may be called to join the nuclear and coal generators: three generators, producing electricity at different emission rates, from two different states, serving a single market.

As this simple example illustrates, the electricity consumed in a given state may or may not be generated in that state. Cross-state electricity flows are inevitable on the present-day electricity system since every state's electric grid is connected to one or more neighboring states, and every state (except Hawaii) trades electricity in some fashion with its neighbors.[2] As a result, there is no practical way to determine where the output from a given power plant is "flowing." To compound the issue, since electricity market boundaries do not align with state boundaries, market operators in one part of a state may be exporting electricity at the same time as their counterparts in another part of the state are importing electricity.

This dynamic creates challenges—and opportunities for efficient interstate emission reduction strategies—as states develop plans in response to EPA guidelines under Section 111(d). Additional renewable generation in one state could reduce fossil generation in another state. Similarly, constraints on a coal plant in one state could result in increased emissions from a natural gas plant in another state. Multi-state approaches to Section 111(d) compliance could take advantage of interstate electricity flows to achieve more cost-effective reductions.

Diverse Supplier Base

Like many commodities, electricity is bought and sold on both wholesale and retail markets. Wholesale electricity is also referred to as "bulk power," and the "bulk power system" describes the infrastructure and operations to generate, transmit, and sell electricity to distribution companies. In this system, transmission lines stretch thousands of miles, linking multiple power plants to customers (see Figure 1). Market operators monitor activity on the grid to make sure that output from those plants is perfectly synchronized with the electricity being used. All of these available resources—including wind farms and coal plants, energy efficiency and demand response, grid-connected storage and other technologies—affect supply and demand on the bulk power market. The bulk power system is owned, operated, and overseen by thousands of companies, government agencies, cooperatives, non-profits, and other entities, which are described in sections 3 and 4 below. All of these entities will be important to consider in the context of Section 111(d) compliance strategies because their combined actions shape power sector emissions at any given moment.

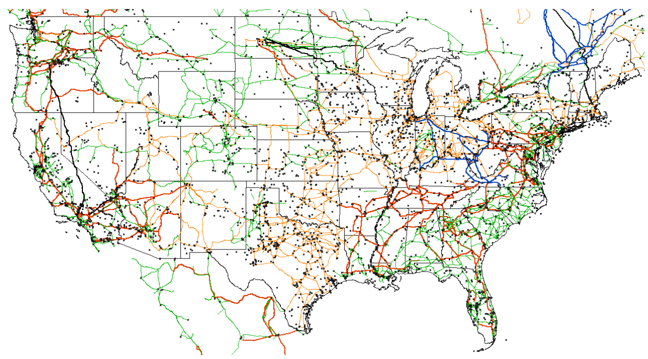

Figure 1: U.S. Bulk Power System (Source: Ventyx Velocity Suite)

[2] Three states offer slight variations on the rule of interstate electricity markets: California, New York, and Texas. Electricity markets in these states are managed, prices are set, and electricity supply and demand are balanced entirely within state borders. The existence of these single-state electricity markets may make it easier to evaluate the individual state implications under Section 111(d). However, interstate electricity trade remains a factor: California imports, on balance, roughly one-third of its electricity from neighboring states, and New York imports about seven percent of its sales, while Texas' trade is flat. Since these figures reflect net yearly trade, actual cumulative electricity flows to and from these states across state and international borders is, in most years, considerably higher.

No Storage

On a multi-year time scale, electricity resembles many commodities. Demand forecasts guide capital investments, as market players seek to match production capacity with forecasted consumption. This exercise, while far from simple, is carried out through resource adequacy assessment and planning, discussed in section 3.

Over the short run, electricity is unique among commodities: there is no affordable, efficient way to store it in large quantities. Corn can be put in a silo, oil in a storage tank, natural gas in a salt cavern. With the benefit of storage, supply and demand for those goods must only match over months or years. For electricity, supply and demand must match instantaneously. The total electrons flowing into the wires from generators must equal the total electrons flowing out of the socket. This requires dynamic and reactive tools to operate the system in real time. Real-time system operations are discussed in section 4.

3. Resource Adequacy Planning

Planning for "resource adequacy" in each state helps ensure that energy and capacity resources will be adequate to meet forecasted energy consumption and peak demand. Any time a policy shift changes the operating constraints for generators, many entities will collaborate to assess the impact on resource adequacy.

A range of entities—from federal and state regulators, to state energy offices, transmission owners, power generators, and electric utilities—will need to work together with state regulators and with EPA to assess how Section 111(d) compliance strategies could affect the electricity system's ability to meet reliability standards. For example, if a company decides to reduce emissions by shifting generation away from higher emitting units and towards lower emitting units, or by retiring a unit and investing in wind resources, there will be a need to evaluate whether the remaining resources will be sufficient to meet demand.

FERC and NERC

At the federal level, the Federal Energy Regulatory Commission (FERC) is responsible for ensuring the safety and reliability of the nation's electricity system and for regulating interstate trade of electricity. As such, it defines operating standards for multi-state electricity markets. It works to promote competition in the electric sector, ensure grid security and reliability, and ensure that planners fulfill public policy objectives.

FERC's role is primarily that of a "guiding hand" for the power sector. Generally speaking, it does not have direct administrative authority over system operations, planning, or investment. It may issue regulations and orders, or require market participants to file plans to explain any changes in their operating plans. It also regulates interstate sales of electricity and pricing of transmission in the bulk power market.

In the context of Section 111(d), FERC can be expected to work with state and regional entities to ensure a smooth transition as they work to achieve compliance with the guidance issued by EPA. If FERC foresees potential issues, it may hold hearings, technical conferences, or other meetings to hear from experts before deciding whether a change to FERC regulations might be necessary.[3] It may also issue guidelines that outline FERC's role in evaluating compliance plans.

For example, in the past FERC has issued statements to help stakeholders identify the types of market reforms that would require tariff revisions—and trigger a need for FERC approval—versus those that would not require tariff revisions.[4] To the extent that compliance plans involve changes to rates and tariffs, FERC's role, as outlined in Section 205 of the Federal Power Act, is largely "passive and reactive," unless it determines that proposed rate and tariff revisions fail the basic test of being just and reasonable.[5]

FERC has appointed the North American Electric Reliability Council (NERC)[6] to oversee reliability standard-setting and enforcement. Together, FERC and NERC will play an important role to ensure that state Section 111(d) plans maintain grid reliability and integrate well with electricity markets.

Integrated Resource Planning

Many regulated utilities prepare Integrated Resource Plans (IRPs) to help utility commissions understand and evaluate alternative resource portfolios. More than 40 state utility commissions require IRPs or similar analyses and use them to develop a long-range plan for the electricity system that takes into account factors such as public policies, projections of future fuel prices, and operating costs.[7] There is wide variability in states' approaches to the IRP process. While some states have minimal requirements for what plans must include, others require that plans consider all resource types (e.g., efficiency, renewables, nuclear, coal) and include extensive analysis of current and potential environmental costs. In Colorado, for example, goals to reduce air pollution have played a central role in resource planning, and their IRPs could serve as a model for other states.[8]

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[3] FERC regularly holds technical conferences to learn from experts and lead dialogues around emerging issues. For example, in February 2014 the Commission announced an upcoming conference on protecting critical infrastructure: FERC, Notice of Technical Conference, http://www.ferc.gov/CalendarFiles/20140227165846-RM13-5-000TC.pdf.

[4] As an example, in 2008 FERC issued a set of guiding principles to transmission system planners who were working on improving their approaches to managing interconnections. *See* FERC News Release, FERC Offers Guidance on RTO, ISO Interconnection Queue Process Improvements, http://www.ferc.gov/media/news-releases/2008/2008-1/03-20-08-E-27.asp. In 2012, FERC issued a statement describing how it would work with EPA to guide the agency's implementation of the Mercury and Air Toxics Standards. FERC, Policy Statement on Commission's Role in EPA's Mercury and Air Toxics Standard, https://www.ferc.gov/whats-new/comm-meet/2012/051712/E-5.pdf.

[5] This principle of review has been clarified in various court decisions. *See, e.g.*, footnote on page 3 of a recent FERC filing by ISO New England. ISO New England Inc. and New England Power Pool Filing on Regulation Market Changes, http://iso-ne.com/regulatory/ferc/filings/2014/mar/er14-1537-000_3-20-2014_reg_mkt_chges.pdf.

[6] NERC is an international not-for-profit regulatory authority whose mission is to ensure the reliability of the bulk power system in the continental United States, Canada, and the northern portion of Baja California, Mexico.

[7] The benefits of IRPs have been outlined in a joint report by RAP and Synapse entitled "Best Practices in Electric Utility Integrated Resource Planning", www.raponline.org/document/download/id/6608.

[8] Colorado's state legislature passed the Clean Air Clean Jobs Act, signed on April 19, 2010, which required the state's rate-regulated utilities to develop plans for reducing air pollutant emissions from coal-fired power plants equaling either 900 MW capacity or 50 percent of their coal fleet. Clean Air – Clean Jobs Act, 2010 Colo. Sess. Laws 466.

State Public Utility Commissions

State public utility commissions (PUCs) oversee the rates and services of retail electricity providers, and may regulate investment in power plants, transmission lines, and distribution networks. Since electric generators are the expected compliance entity under Section 111(d), the key question regarding PUCs is the role they will play in regulating or influencing the investment decisions of generating companies.

From state to state, PUCs will take different approaches due to policy, political, and regulatory differences. This process varies depending on the state's level of market regulation.[9] In fully regulated states, utilities are typically vertically-integrated, owning generation, transmission, and distribution. Customers have only one choice of electricity provider, and the same company provides the service and the supply. In restructured—sometimes called "deregulated"—markets, customers may have retail choice, with the option to buy electricity from a number of different power suppliers. In restructured markets, electricity distribution companies are often restricted from owning power plants. Most of the fully regulated states can be found in the West and the Southeast, while many states in the Northeast and Midwest have undergone restructuring.

PUCs are mandated by state statutes to ensure electricity rates are just and reasonable, and will act within their authority to examine regulated utilities' added costs to secure emission reductions within that framework. A PUC might support a regulatory filing that proposes investments in demand-side energy efficiency, for example, because of the cost savings such investments provide for consumers. PUCs will also consider how Section 111(d) compliance affects resource adequacy. For example, if a vertically integrated utility proposes to shut down a generating unit to reduce emissions, the PUC will work to preserve reliability by evaluating the availability of other generating resources.

Regulated utilities file plans with their PUCs that detail the retail rates they estimate are necessary in order to cover both fixed and variable costs. These costs might include, for example, capital expenditures for power plant construction or retrofits, fuel costs, transmission line upgrades, utility pole replacement programs, emission allowance costs, customer billing software, and so on. In regulated states, therefore, utilities could gain assurance in advance that projected Section 111(d) compliance costs could be recouped.

For regulated utilities that do not also own generation, PUCs have less control over capital investments. Although commissions review and approve retail tariffs, transmission and distribution costs, and other spending categories, they allow the market to control the resource mix and typically do not regulate investment in generators. Under Section 111(d), any additional costs incurred by generators would likely show up in wholesale power prices. Utilities would then have to incorporate their adjusted energy procurement costs into the plans they file with their PUCs. Since they do not have any direct control over investments in generation, PUCs would most likely evaluate the utilities' energy procurement strategies, rather than judging the compliance costs themselves. However, if a state's compliance plan includes utility investment of ratepayer funds in measures such as demand-side energy efficiency or renewable energy, PUCs will have the authority to review this investment.

[9] Fifteen states have "restructured" their retail electricity markets: OR, TX, IL, MI, OH, PA, MD, DE, NJ, NY, CT, RI, MA, NH, and ME. Restructuring is the process of introducing increased amounts of competition into the electricity market.

Regional Entities

Multi-state coordination is common in electricity system planning, and numerous regional entities cooperate on different pieces of the puzzle. NERC oversees eight regional reliability councils, comprising utilities, power generators, power marketers, and end-use customers, which work to ensure adequate resources will be available to customers in their region. These councils cover between one and thirteen states and are charged with comparing future resource availability against future demand. The work of these councils is informed by a collection of planning areas, shown in Figure 2. These planning areas are generally overseen by electric utilities (investor-owned, municipal, cooperative, and federal power authorities), as well as Regional Transmission Organizations (RTOs).[10] The boundaries of NERC reliability regions do not match those of RTOs, although RTOs provide significant input to the NERC regional entities.

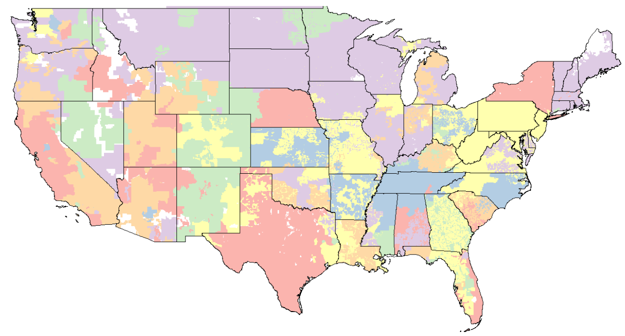

Figure 2: U.S. Planning Areas. (Source: Ventyx Velocity Suite)

In addition to the reliability councils, an array of other regional entities and coalitions often provide input into planning processes. For example, the Southeastern Electric Exchange, the Northwest Public Power Association, and the New England Power Generators Association all represent utilities and power generators. The New England Power Pool (NEPOOL) is a diverse association of market participants representing generators, transmission companies, suppliers, and end users of electricity. The New England Conference of Public Utilities Commissioners (NECPUC) and the Southeastern Association of Regulatory Utility Commissioners (SEARUC) are two regional associations of public utility commissioners. Each of these groups, and many others like them around the country, arranges member forums to facilitate the flow of information, considers and acts on pertinent policy and market proposals, and synthesizes comments when there is an opportunity to participate in stakeholder processes.

Given that Section 111(d) is likely to affect generators, planners, and market operators, and given the extensive interstate electricity trade that takes place, regional entities can be expected to be engaged before and after Section 111(d) standards and state compliance plans are finalized.

Before the standards are finalized, regional entities will likely begin to prepare by coordinating with one another. They can also be expected to participate in the public comment process during development of state compliance plans. Regional entities commonly provide feedback on rulemakings. As an example, the ISO/RTO Council, which is a collaboration of Independent System Operators (ISOs) and RTOs, has already submitted comments to EPA on Section 111(d).[11] Similarly, ISO New England, which is the New England-area RTO, and other regional coalitions were actively involved in developing the two model rules for the Regional Greenhouse Gas Initiative (RGGI). They helped RGGI market designers understand the impacts of proposed rules on electricity markets.

[10] An RTO is an independent, standalone, non-profit organization set up by a consortium of transmission owners and grid operators to manage grid operations and electricity markets, and oversee system planning within a defined area. RTOs operate the grid on behalf of transmission owners, generators, and customers. Independent System Operators (ISOs) perform the same function as RTOs, with the slight difference that they are formed at the direction of FERC.

[11] ISO/RTO Council, EPA CO2 Rule–ISO/RTO Council Reliability Safety Valve and Regional Compliance Measurement and Proposals, January 28, 2014, http://www.isorto.org/Documents/Report/20140128_IRCProposal-ReliabilitySafetyValve-RegionalComplianceMeasurement_EPA-C02Rule.pdf.

Once the standards have been finalized, regional entities will need to incorporate revised assumptions into their planning models and participate in negotiations to establish any appropriate multi-state collaborations. For example, the Southwest Power Pool (SPP), which serves as a regional reliability council in the southwest, incorporates assumptions about emission allowance costs when it performs cost-benefit analyses of potential market design changes.[12] WECC, the Western Region Reliability Council, has conducted analyses to determine how California's AB32 greenhouse gas regulations should shape transmission planning in the West.[13]

RTO and non-RTO Regions – Planning

Electricity system planning and coordination takes place in both RTO and non-RTO regions, although the mechanisms for planning and coordination differ. RTOs plan and coordinate transmission for nearly two-thirds of all U.S. electricity systems. Participation by transmission system owners in an RTO is voluntary, but subject to PUC approval. As shown in Figure 3, the U.S. has seven RTOs/ISOs, including the PJM Interconnection, the Midcontinent Independent System Operator (MISO), ISO-New England, the California ISO (CAISO), the New York ISO (NYISO), the Southwest Power Pool (SPP), and the Electric Reliability Council of Texas (ERCOT).

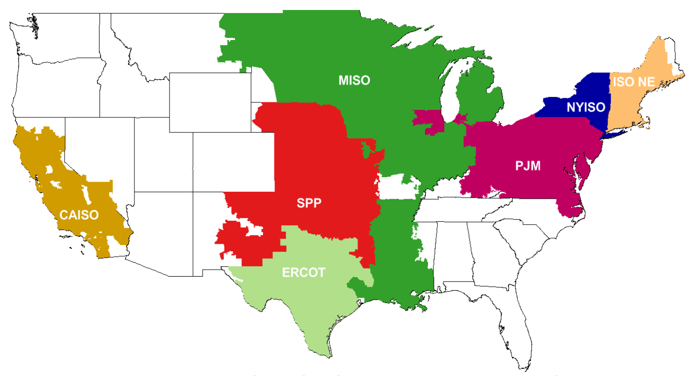

Figure 3: U.S. RTOs (Source: Ventyx Velocity Suite)

The largest non-RTO region in the U.S. is in the West, where public and investor-owned utilities (IOUs), system operators, independent power producers (IPPs), state agencies, cities and towns, trade associations, and various stakeholders participate in the Western Electricity Coordinating Council (WECC). WECC is one of the eight regional reliability councils designated by NERC to oversee system planning. Within WECC, utilities have formed several regional initiatives, including ColumbiaGrid, Northern Tier Transmission Group, and WestConnect. These entities are not formally RTOs, but perform many of the same long-term planning functions.

Another large non-RTO region is the Southeast, where the SERC Reliability Corporation (SERC) is responsible for overseeing regional reliability and leading coordination among parts or all of sixteen states.

Electricity system planning and coordination differ between regions that are within an RTO and those that are not. In general, in non-RTO regions, the level of market regulation tends to be higher, and PUCs exert greater influence in planning through administrative control over market pricing, investment, and market rules. In RTO regions, PUCs exert less influence over planning, and pricing and investment are the outcome of market rules and incentives, which RTOs manage on behalf of a large number of regional market participants.[14]

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[12] *See, e.g.*, Ventyx, Southwest Power Pool Cost Benefit Study for Future Market Design (April 7, 2009). http://www.spp.org/publications/cost_benefit_study_for_future_market_design.pdf

[13] *See, e.g.*, WECC, Draft Scoping Document, California AB32 Sensitivity Case for 2011 TEPPC Study Program (April 2012), http://www.wecc.biz/Lists/Calendar/Attachments/4502/TEPPCMWG_2022AB32_DRAFTScopingDoc.pdf.

[14] There are exceptions to this rule; utilities may be subject to grandfathered agreements, legislated provisions, or other special cases.

4. Scheduling, System Control, and Dispatch

Real-time operations of the electric grid are handled by grid operators. In RTO regions, this function is performed by RTOs. In non-RTO regions, grid operations and electricity dispatch are managed by electric utilities, which oversee "control areas" or "balancing authorities" for a defined region. In some places, federal power agencies serve this role. While decision rules and approaches vary around the country, in general, grid operators develop projections of electricity demand one or more days ahead of time and "schedule" generators by providing notice that they will be needed at a given time on a given day. In real-time, grid operators call, or "dispatch," the necessary units and instruct them to provide power.

The choice of which generators to dispatch is usually based on the marginal operating costs of each unit. In competitive markets, marginal operating costs are reflected in bids provided by generators, indicating the price at which they are offering to provide electricity and the amount of electricity they could provide at that price. Elsewhere, the grid operator has a list of available generators, their capacities, and their marginal operating costs. (Bids are generally based on these same factors.) In both cases, marginal operating costs include fuel costs, the variable costs of operations, and certain environmental costs, such as the cost of emission allowances.[15] The lowest-cost generators are called first, followed by the more expensive ones, until the cumulative capacity matches the total capacity demand.[16] This approach is known as "least-cost" or "economic" dispatch.

While most dispatch decisions reflect the least-cost principle, system operators may in certain circumstances take other factors into account in dispatch decisions, and choose to dispatch units "out of merit." For example, if demand is especially high in a given region, a system operator could choose to dispatch a generating unit due to its proximity to the demand, to overcome transmission congestion. The system operator could also choose to dispatch a unit to help ensure system reliability. In addition, dispatch may not include all of the lowest-cost units in a given market if generators choose not to offer their capacity to the market due to operating limitations.

Marginal Costs of Environmental Compliance

In the context of Section 111(d), one potential approach to reducing carbon pollution in the electricity sector is to reshuffle the dispatch order to account for greenhouse gas emissions. There are numerous ways to achieve this, such as (1) for the system operator to add an emissions fee to each generator's costs, (2) for each generator to be required to hold emissions allowances, the cost of which would be reflected in the marginal costs, (3) for units to be subjected to utilization limits, or (4) for fuels to be given dispatch preference based on carbon emissions. All of these approaches, and others, could theoretically be integrated into current approaches to dispatch. Already, generators include the cost of sulfur dioxide (SO_2) and nitrogen oxide (NO_x) allowances when they submit marginal cost bids to the system operator. In states that participate in RGGI, many generators include RGGI allowance costs in their bids to the ISO-NE and PJM market operators.

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[15] The extent to which marginal costs include environmental costs is highly dependent on policy. Some environmental costs have been internalized into the operating costs, while others are not, and are instead borne by society.

[16] A single market "clearing price" based on the highest marginal operating cost of units that will be dispatched will be paid to generators who participate in the market at a specified time. Therefore, generators with operating costs lower than the clearing price will earn profits from selling electricity. The profit is equal to the difference between the clearing price and their operating costs.

As part of a compliance plan, some emissions reductions may be attained through investments in the plant. As an example, a generator may invest in on-site efficiency measures. The capital investment in efficiency is not reflected in a generator's variable operating costs, but would be factored into the fixed costs that the generator must cover, either by seeking regulatory approval for cost recovery, or by earning profits on its sales of electricity and other services to the grid. (If the generator incurs costs to *run* the new equipment, those costs would be included in the marginal operating costs.) In regions where regulated plants and merchant plants compete against each other in the electricity market, regulated plants will benefit from greater certainty around their ability to recoup the efficiency investment.

Given the interstate nature of dispatch within the electricity system, dispatch will be affected by differences between states' Section 111(d) compliance plans that value carbon reductions differently in different states. For example, similar power plants competing in the same market or power pool could face very different compliance costs, which would change their competitiveness relative to each other.

Public Power Utilities

About 15 percent of the U.S. is served by community-owned utilities, notably municipal utilities and rural electric cooperatives ("munis and coops"). These utilities are owned by and accountable to customers, and in the case of munis, are administered by local municipal governments. They are generally not regulated by state utility commissions. Some of these entities own their own power generation, while others do not. The same principles of scheduling and dispatch apply to the power sold by munis and coops as those described above. In most cases, these entities purchase their power from suppliers who participate in an RTO market or are dispatched by a control area operator. The electricity sold by a muni or a coop to a customer may reflect economic dispatch, or it may reflect power purchase agreements between the muni/coop and a generator.

Public power utilities that own generation will be sensitive to compliance costs of their own fleet. Those that purchase power from the grid will be interested in understanding how the wholesale market price of electricity may be affected by state plans to reduce carbon emissions, and how their existing power purchase agreements are recognized under the relevant state's compliance plans.

Table 1: Anticipated Priorities of Regulators and other Market Entities.

	Likelihood that these entities…							
...will evaluate how 111(d) could affect…	FERC	NERC	PUC	RTO	IOU	Muni/Coop	IPP	Stakeholders
… retail power prices.			Definite		Definite	Definite		Definite
… resource adequacy.	Definite	Definite	Definite	Definite	Definite	Definite	Possible	Possible
… system reliability.	Definite	Definite	Definite	Definite	Possible	Possible	Possible	Definite
… transmission needs.	Definite	Possible	Possible	Possible	Possible	Possible	Possible	
… generator dispatch.			Possible	Definite	Possible	Possible	Possible	Possible
… wholesale electricity markets.	Definite		Possible	Definite	Possible	Possible	Possible	
… retail utility operations.			Definite		Definite	Definite		Definite

5. Conclusion

Maintaining a reliable electricity system requires the participation and input of many diverse entities with a mix of local, state, regional, and national authorities. The overlap between them speaks to the need for effective cooperation throughout the development of state plans under Section 111(d). Because a substantial share of U.S. electricity consumption crosses state lines, states will want to consider how best to drive efficient outcomes across multi-state markets. Many of the regulatory and market processes that could underpin a sound approach to carbon pollution reduction policies can already be found in practice.

Funding for this project was provided by The William and Flora Hewlett Foundation. The Georgetown Climate Center is grateful for their support and the support from all of the funders who make our work possible: http://www.georgetownclimate.org/support.

Please contact Gabe Pacyniak (pacyniak@law.georgetown.edu) with any questions.

GEORGETOWN CLIMATE CENTER

Walking the Line Between the Clean Air Act and the Federal Power Act: Balancing Emission Reductions and Bulk Power Reliability

A power plant can find itself subject to potential liability under the Clean Air Act if it does not cease or greatly reduce operations and at the same time be compelled by the Department of Energy and/or the Federal Energy Regulatory Commission acting under the Federal Power Act to keep operating to ensure reliability. There needs to be cooperation among the federal agencies to create a stable and predictable regulatory environment at a minimum and, more preferably, a comprehensive solution to prevent this conflict from occurring in the first place.

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Recent rounds of regulations by the Environmental Protection Agency (EPA) have renewed a critical unresolved legal question for operators of power plants, one that impacts the reliability of the nation's bulk power grid: What happens when a plant is subject to potential liability under the Clean Air Act (CAA) if it does not cease or greatly reduce operations, and at the same time is compelled by the Department of Energy (DOE) and/or the Federal

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Energy Regulatory Commission (FERC) acting under the Federal Power Act (FPA) to keep operating to ensure reliability? Although this scenario may arise for plants installing emission control systems to obtain compliance with the CAA, conflict between the CAA and the FPA is more likely to arise for plants seeking to retire rather than install control systems for which reliability solutions such as new generation or transmission upgrades are not practical under the time constraints imposed by the CAA. In this article we summarize the statutory background for such potential conflicts between the CAA and the FPA, explore previous instances where these laws were in conflict, and discuss the recent regulations and how conflicts arising under them might be addressed by EPA, DOE, and FERC.

I. Bulk Power Reliability and the Federal Power Act

Both DOE and FERC have ways to address bulk power reliability concerns pursuant to various provisions of the FPA. DOE has invoked its authority several times since 2000, while FERC has only invoked its authority once and in a manner complementary to authority already exercised by DOE.

A. DOE's authority under the FPA

Section 202(c) of the FPA empowers the Secretary of Energy to order power plants to operate for reliability reasons during emergency situations. The statute specifically provides that ''whenever the Commission determines that an emergency exists . . . the Commission shall have authority . . . to require by order such temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest.''[1]

Conflict between the CAA and FPA is more likely to arise for plants seeking to retire rather than install control systems for which reliability solutions such as new generation or transmission upgrades are not practical.

Even though the language in the FPA refers to ''the Commission,'' the authority to require power plants to operate in fact lies with the Secretary of Energy and DOE. The Department of Energy Organization Act transferred the powers previously vested with the Federal Power Commission to DOE unless the authority is expressly reserved to FERC.[2] While DOE has vested certain powers with FERC, such as those provided in Sections 202(a) and 202(b) of the FPA, DOE has retained its authority under Section 202(c).

Not only has DOE retained this authority, it has interpreted its potential application broadly. DOE has defined an ''emergency'' to include, among other things, ''an unexpected inadequate supply of electric energy.''[3] Perhaps presciently, DOE also included ''regulatory action which prohibits the use of certain electric power supply facilities'' in its definition of ''emergency.''[4]

However, Section 202(c) does not require DOE to take action; instead, it simply provides DOE with the authority to take action if it so chooses. As discussed in more detail below, DOE has invoked this authority in several instances since 2000.

B. FERC's authority under the FPA

Section 202(c) is not the only provision of the FPA that appears to provide a federal agency with the authority to ensure the reliability and adequacy of electric service. Section 207 of the FPA states that upon a complaint by a state commission, ''[w]henever the Commission . . . shall find that any interstate service of any public utility is inadequate or insufficient, the Commission shall determine the proper, adequate or sufficient service to be furnished, and shall fix the same by its order, rule or regulation . . . .''[5]

While this authority lies with FERC, it has only been invoked on one occasion—and in that instance, DOE had already ordered a plant to generate

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electricity pursuant to Section 202(c). Specifically, in 2006, FERC used its authority under Section 207 to require PJM Interconnection, LLC, (PJM) and the Potomac Electric Power Company (''Pepco'') to ''file a long-term plan to maintain adequate reliability in the Washington, DC, area and surrounding region, and a plan to provide adequate reliability pending implementation of this long-term plan.''[6] Aside from this instance, FERC has refrained from using this authority.[7]

However, Section 207 arguably allows FERC to consider reliability concerns in determining whether a utility is providing adequate or sufficient service.[8] While FERC's authority is contingent upon a complaint by a state commission, Section 207 mandates that FERC take action to remedy the problem upon a finding of inadequate service.[9] In contrast, Section 202(c) simply provides DOE with the discretion to take action, though DOE can do so on its own accord.[10]

Section 309 of the FPA augments FERC's authority by permitting it ''to perform any and all acts, and to prescribe, issue, make, amend, and rescind such order, rules, and regulations as it may find necessary or appropriate to carry out the provisions of [the FPA].''[11] Courts, however, have narrowly construed Section 309, stating that it ''merely augment[s] existing powers''[12] and allows FERC to ''use means of regulation not spelled out in detail.''[13] As such, FERC would most likely need to rely on another provision, perhaps in conjunction with Section 309, to address reliability concerns.

II. EPA's Authority under the Clean Air Act to Regulate Power Plants

EPA has broad authority to regulate power plant operation. For coal fired-power plants, EPA has recently proposed and in some cases finalized new regulations that would affect emissions of pollutants, handling of the byproducts of coal combustion, and cooling-water intake structures. These regulations are promulgated under the CAA, the Resource Recovery and Conservation Act (RCRA), and the Clean Water Act (CWA), respectively. Although all of the rules published by EPA have the potential to impact reliability, EPA's recently finalized emissions limits for hazardous air pollutants and for pollutants that cross state lines for utility-scale energy generating units will be the first to impact operating power plants. As the RCRA rules relating to coal combustion byproducts and the CWA rules on cooling water intakes are still in the draft stage, with no clear statutory deadline for implementation, we focus our discussion on the potential conflict between the CAA rules and FERC and DOE's responsibilities under the FPA.

> *Section 207 arguably allows FERC to consider reliability concerns in determining whether a utility is providing adequate or sufficient service.*

A. EPA's authority under the CAA

1. National Ambient Air Quality Standards

EPA is directed under Section 109(b)(1) of the CAA to create national standards, the National Ambient Air Quality Standards (NAAQS), to limit levels of pollutants that are harmful to public health and welfare.[14]

The CAA is a partnership of federal and state regulation, with Section 110 directing each state to adopt a State Implementation Plan (SIP), which EPA must then approve.[15] Once approved, the SIP is effectively a federal law, and enforceable as such.[16] The CAA further provides that once approved, no federal entity ''shall engage in, support in any way, or provide financial assistance for, license or permit, or approve, any activity which does not conform to an implementation plan after it has been approved . . ..''[17] The statute defines conformity as:

''(A) conformity to an implementation plan's purpose of eliminating or reducing the severity and number of violations

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of the [NAAQS] and achieving expeditious attainment of such standings; and

(B) that such activities will not -

(i) cause or contribute to any new violation of any standard in any area;

(ii) increase the severity of any existing violation of any standard in any way; or

(iii) delay timely attainment of any standard or any required interim emission reductions or other milestones in any area.''[18]

Although broadly drafted, there are limitations on the scope of the conformity requirement. Initially, the conformity analysis only covers ''major'' federal actions; for actions emitting less than the threshold, conformity is presumed.[19] *De minimis* actions are also explicitly excluded by regulation.[20] EPA's regulations also specifically exclude ''actions in response to emergencies or natural disasters such as hurricanes, earthquakes, *etc.*, which are commenced on the order of hours or days after the emergency or disaster'' or ''actions which are a part of a continuing response'' to said emergency or disaster, although the federal agency taking the action must make a written determination that the conformity analysis is impractical for a period of up to six months ''due to overriding concerns for public health and welfare, national security interests and foreign policy commitments.''[21] CAA Section 110(f) also contains a non-delegable Presidential temporary waiver for energy emergencies, which is limited to a period of four months.[22] Some courts have interpreted EPA's authority to act pursuant to the CAA as discretionary, with the court in *Seabrook v. Costle* noting that no section of the CAA ''imposes a mandatory duty on the Administrator to make a finding every time some information concerning a possible violation of a SIP is brought to [her] attention.''[23]

Although broadly drafted, there are limitations on the scope of the conformity requirement.

The NAAQS provisions of the CAA do not directly address conflicts with other laws.

2. Mercury and Air Toxics Standards

EPA is directed under Section 112 to regulate power plant emissions of hazardous pollutants. Congress required EPA to study power plant emissions of hazardous air pollutants under Section 112(n)(1). Following presentation of that study to Congress, the statute required EPA to regulate power plants ''if the Administrator finds such regulation is appropriate and necessary.''[24] EPA issued a determination that regulating the emissions of hazardous air pollutants from power plants was ''appropriate and necessary'' in 2000,[25] and promulgated regulations that have since been vacated by the D.C. Circuit.[26] Subsequently several environmental and public health organizations filed a complaint alleging that EPA had not performed a mandatory duty under the CAA to regulate hazardous air pollutants from coal and oil-fired electrical generating units (EGUs).[27] EPA settled the case, and under the consent decree was required to issue a notice of final rulemaking by Dec. 16, 2011.[28]

The Mercury and Air Toxics Standards (MATS) standards for existing power plants are technology-based emissions limits, with the Administrator required to set levels equivalent to the average emissions of the best-performing 12 percent of plants.[29] EPA must set the effective date no later than three years after the rule is published.[30] Under the CAA, either the administrator or a delegated state may issue an extension of up to one year ''if such additional period is necessary for the installation of controls.''[31] The President may also grant an exemption for up to two years if ''the President determines that the technology to implement such standard is not available and that it is in the national security interests of the United States to do so.''[32]

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As with the NAAQS, there is no language under the MATS that clarifies how to resolve conflicts with other laws. Similarly, there is no language in the other sections of the CAA. The CAA does generally provide authority for citizen suits against any person, including the administrator, for violations of the act or failure of the administrator to perform a required duty.[33]

III. Past Conflicts between the CAA and the FPA

Bulk power reliability concerns have led DOE to exercise its authority under Section 202(c) of the FPA on several occasions since 2000. For example, DOE ordered the Cross-Sound Cable, an underwater transmission line running between Connecticut and Long Island, to operate during back-to-back summers due to a summer heat wave in 2002[34] and the Northeast Blackout in 2003.[35] However, there have been two instances in recent years where some electric power generators have faced a dilemma between complying with the CAA and following an order under the FPA to generate electricity.

A. The Potomac River Generating Station

The Potomac River Generating Station is a 482 MW coal-fired power plant in Alexandria, Va., that provides electricity for portions of the District of Columbia, including the Blue Plains Advanced Water Treatment Plant—one of the largest wastewater treatment plants in the world.[36] On Aug. 19, 2005, Mirant Corporation, the owner of the station, submitted a computerized emissions model to the Virginia Department of Environmental Quality (VDEQ) indicating that emissions from the station either caused or contributed to localized exceedances of the NAAQS.[37] In response to a subsequent letter from VDEQ, Mirant shut down all five of the station's generating units on Aug. 24, 2005.[38]

Bulk power reliability concerns have led DOE to exercise its authority under Section 202(c) of the FPA on several occasions since 2000.

That same day, the District of Columbia Public Service Commission (DCPSC) filed a petition with both DOE and FERC requesting that Mirant be compelled to operate the station to maintain reliability in the District of Columbia.[39] Based on the ''reasonable possibility an outage will occur that would cause a blackout,'' DOE responded to the DCPSC's petition by ordering Mirant to resume operations pursuant to Section 202(c) of the FPA.[40] FERC also responded by requiring long-term reliability plans from PJM and Pepco pursuant to Section 207 of the FPA.[41]

DOE's order to resume operation did not, however, expressly alleviate Mirant from possible penalties for exceeding the NAAQS. In its order, DOE sought to walk the line between reliability and potentially adverse environmental impacts by specifying the manner in which Mirant was to operate the station. DOE also stated that if EPA issued a compliance order, then DOE would consider whether and how to conform its order accordingly.[42] Sure enough, six months later, EPA issued a compliance order instructing Mirant to use SO_2 emission controls and to operate only when daily modeling indicated that it would comply with the NAAQS.[43] However, the compliance order also required Mirant to operate the station ''as specified by PJM and in accordance with the [2005] DOE Order.''[44]

Mirant successfully operated the station pursuant to the orders by DOE and EPA for over a year. On Feb. 23, 2007, however, Mirant's luck ran out. By operating in accordance with DOE's order to run for reliability purposes, the station exceeded its three-hour NAAQS limit and the VDEQ consequently fined Mirant for NAAQS exceedances.[45] This situation was unfortunately not the first time a

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generator faced a dilemma involving the CAA and the FPA.

B. The California Energy Crisis

Near the end of 2000 and into 2001, the state of California experienced an unexpected electricity shortage. DOE responded by ordering certain generation facilities to make energy available to the California Independent System Operator (CAISO) for a period of approximately two months.[46]

In addition to the action taken by DOE, FERC also instituted a ''must-offer obligation'' mandating that all non-hydroelectric generators offer all of their available capacity into the spot market during all hours.[47] In light of comments filed by generators, FERC recognized that the must-offer obligation could result in generators operating in violation of their certificates or applicable law. To mitigate this situation, the must-offer requirement did not require generators to run if doing so would otherwise break the law.[48] In a subsequent order, FERC clarified that a generator could go so far as to seek a declaratory order from the courts finding that compliance with the must-offer obligation would result in permit violations if it wanted to prevent citizen suits alleging violations of environmental regulations.[49] This clarification came about in response to a citizen suit against a generator, which the generator settled at a significant cost.[50]

IV. Potentially Potent Rulemakings

A. EPA's finalized regulations

1. Cross-State Air Pollution Rule

On July 6, 2011, EPA finalized regulations requiring significant reductions in SO_2 and NO_x emissions.[51] EPA issued the regulations in response to the D.C. Circuit's remand of a prior version of the rule, the Clean Air Interstate Rule (CAIR).[52] EPA proposed technical adjustments on Oct. 6, 2011, and finalized a supplemental rule including additional states on Dec. 17, 2011.[53] EPA estimates that costs associated with CSAPR are \$800 million annually in 2014, on top of \$1.6 billion per year in capital investments that were being made in response to the previous rulemaking.[54] EPA expects facilities to use dry and wet flue-gas desulfurization (FGD), dry sorbent injection, selective catalytic reduction (SCR), and some fuel switching and process optimization.[55] The initial compliance phase was to begin on Jan. 1, 2012; however, the D.C. Circuit stayed CSAPR on December 30, 2011 in *EME Homer City Generation, L.P. v. EPA* and ordered the parties to propose briefing schedules so that the case could be heard by April 2012.[56] As the rule stands now, the second, more stringent compliance phase begins on Jan. 1, 2014.[57]

2. MATS for Utility Generators

On Dec. 16, 2011, EPA finalized regulations limiting the emissions of mercury and other hazardous pollutants from EGUs.[58] EPA estimates that the total cost of the rule will be \$9.6 billion annually in 2015.[59] Some industry estimates are significantly higher.[60] EPA expects plants that are installing controls to use a mixture of available technologies, including SCR with FGD, activated carbon injection (ACI), ACI with a fabric filter, dry sorbent injection, and electrostatic precipitators.[61] Costs for individual plants will vary, but for facilities with no pollution controls, compliance costs are expected to run into the hundreds of millions of dollars per plant.[62] EPA made small revisions to the proposal as a result of comments received, which according to EPA's estimates reduced the costs of compliance by about \$1 billion.[63]

EPA grants the statutory maximum of three years and 60 days from the published date for compliance with the MATS rule, meaning the earliest compliance date would be March 2015.[64] As discussed above, generators that are installing controls may be eligible for an additional one-year extension from either the state managing the program or the administrator.[65] In two memoranda released with the final rule, one from EPA and one from the President, the administration states that although unlikely to be required, EPA can issue administrative orders that would absolve violators who were operating subject to critical reliability concerns of complying with the CAA for one year under Section 113(a) (governing enforcement of violations).[66] However, as discussed above, prior experiences indicate that the administrative order process may not protect against all risks to companies required to operate for reliability reasons, as citizen suits may be filed by individuals or organizations other than EPA. The memoranda also make clear that the administration intends to make the standard one-year extension for installation of controls under Section 112 (i)(3)(b) ''broadly available''; however, the applicability of that extension to facilities that plan on retiring is uncertain.[67] Neither memorandum mentions the President's authority under Section 112 (i)(4), so the breadth of that additional exemption, and the administration's willingness to invoke it, are unclear.

B. EPA's proposed regulations

EPA has also proposed two other rules that are likely to have a significant cost impact on certain coal-fired electrical generating units, potentially including some that are critical to reliability. The first rule, proposed on June 21, 2010,[68] with a subsequent Notice of Data Availability issued on Oct. 12, 2011,[69] deals with the treatment of coal combustion byproducts. Two regulatory schemes were proposed by EPA under RCRA, with the first being to regulate coal combustion residuals under Subtitle C of RCRA, which covers the cradle-to-grave treatment of hazardous waste. EPA's second proposal would regulate the coal byproducts under Subtitle D of RCRA, the section regulating non-hazardous wastes. EPA has indicated that a final rule will not be issued until late 2012; thus the nature of the regulation and the timeline for implementations are unclear.[70]

The second proposed regulation is for the intake of cooling water. EPA has proposed regulations that would cover the impingement (trapping of fish against the intake screen) and entrainment (fish that are drawn into the power plant and affected by heat or other stress) of fish and other aquatic life.[71] EPA has signed a consent decree with the environmental group Riverkeeper indicating that it will issue final actions by July 27, 2012, although the implementation period for existing plants is still unknown.[72]

C. Anticipated impacts on bulk power reliability

At least a dozen studies have attempted to analyze the potential reliability impacts associated with the recent suite of new regulations by EPA. However, all of these studies face the same problem—we do not have all of the final rules yet, and companies' responses to the finalized rules are still being developed.

At FERC's recent Reliability Technical Conference, PJM pointed out that there is a chicken-or-the-egg issue with respect to identifying the impacts on reliability that the proposed rules will have before EPA issues its final rules.[73] The problem is that reliability impacts cannot be reliably estimated until generators identify which units they will retire. At the same time, generators cannot know which units to retire until they have all of the final rules from EPA and have had time to analyze the final regulations. So, in the meantime, the best approach is to attempt to identify all ''at risk'' generation to understand the possible spectrum of reliability impacts.[74] As a result, there is a variety of studies that make varying assumptions and come to sometimes

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dramatically different conclusions.[75]

Regardless of the extent of retirements anticipated across the country, the situation with the Potomac River Generating Station indicates that the early retirement of even a single plant can lead to a localized reliability issue. Accordingly, DOE, FERC, and EPA should take steps to coordinate the implementation of these rules in a predictable manner that does not place generators in the position faced by the Potomac River Generating Station.

V. Potential Outcomes for Resolving Reliability Conflicts

EPA, FERC, utilities, and regulators have all proposed a number of different solutions for resolving any potential conflict. We discuss below a number of the solutions that have been proposed or that are present in the underlying statutes. These solutions can generally be grouped into three categories: actions by EPA or the states to waive environmental laws, Presidential extensions, or actions by DOE or FERC to force regulated entities to violate environmental laws, while potentially protecting those entities.

A. Reliability safety valve

Although this phrase has been incorporated into a number of different proposals describing different mechanisms, most commonly the ''reliability safety valve'' refers to a proposal put forward in joint comments on the MATS proposed rule from several independent system operators (ISOs) and regional transmission organizations (RTOs).[76] The Joint RTO Commentors proposed that a retiring generator that is determined to be critical for system reliability be allowed to operate for an additional fourth year, or longer if more time is required to address the reliability issue.[77] The RTO comments propose limiting the extension to situations where the generator provides an early notice of impending retirement, the ISO/RTO identifies the unit as critical to reliability, and the upgrades or replacements necessary to address the reliability problem are expected to take more than three years.[78]

EPA has adopted some aspects of this proposal into its enforcement memorandum issued with the final MATS rule, although the additional extension for units critical to reliability would operate *via* administrative order under Section 113(a), and would be limited to a period of one year.[79] On the other hand, neither the Presidential memo nor EPA enforcement memorandum clarify whether the separate ''broadly available'' one-year extension under Section 112(i)(3)(B) would be available to facilities that are shutting down.[80] Notably EPA indicates that the administrative orders under Section 113(a) would be granted to facilities that are moving into retirement, not just for facilities installing controls, or being replaced with new generation onsite.[81] Potentially more problematic is EPA's statement that the orders would not be issued before the compliance date, creating the potential for a conflict until the order is posted.[82] In addition, the administrative orders may not remove risks from citizen suits, as previously discussed in the context of the California energy crisis.

A longer-term solution could be to amend the FPA to make clear that those operating under an emergency order issued by DOE pursuant to its authority under Section 202(c) of the FPA are not subject to civil or criminal liability for violating environmental laws or regulations.[83] This has the advantage of addressing any future concerns under other environmental statutes, but may be challenging to pass in a tough legislative environment.

B. Presidential extensions

Under both CSAPR and MATS, the CAA includes a Presidential waiver that could be used to temporarily extend compliance deadlines for individual facilities. While the administration has not expressed a view as to the potential for use of these statutory exemptions, they remain possible uses for particular situations. Although the CSAPR exemption is limited to only four months by the statute, the Presidential exemption under Section 112 could theoretically be reissued indefinitely for two-year terms if required. Given the potential for long timelines for siting new power plants and transmission lines, this backstop authority may become useful if the other extensions EPA has proposed are exhausted.

C. Compelled operation to protect bulk power reliability

If an extension, consent decree, or similar waiver cannot be obtained for a unit that is critical to reliability, DOE might choose, as it has previously, to apply its authority under FPA Section 202(c) to require a facility to run. Yet none of the issues raised by the Potomac River and California Energy Crisis situations discussed above have been resolved, leading to significant uncertainty for plant operators. Under FERC's supervision, units that are critical to reliability and planning to retire may be able to negotiate distributed financial burdens for installing controls, or indemnity against any future costs.[84] Alternatively, similar to the FERC's approach during the California energy crisis, any orders that require a generating facility to operate could be limited so as to make clear that the order would not apply if compliance would result in a violation of the facility's certificate or applicable law.

VI. Which Statute Controls if Another Conflict Arises?

Despite the numerous proposals and possible coordination among federal agencies, it is plausible that another conflict will occur between the CAA and the FPA, just as it did with respect to the Potomac River Generating Station. If another conflict occurs, the question of which statute controls may very well come before the courts.

A court will first look to the statutes to see if either specifically addresses conflicts of law.[85] In this case, neither the CAA nor the FPA expressly or impliedly trump one another. In the absence of a conflicts-of-law provision, a court will then attempt to harmonize the provision so as to avoid the conflict.[86] As discussed above, there is a potentially critical difference between Sections 202(c) and 207 of the FPA in that DOE's authority under Section 202(c) is discretionary, while Section 207 mandates FERC to ''fix'' inadequate service. Courts have held that certain environmental statutes must yield if their application prevents a federal agency from fulfilling a nondiscretionary legislative mandate.[87] Because of the nondiscretionary mandate of Section 207, a court could find that FERC's action pursuant to Section 207 cannot be waived or limited by conflicting CAA provisions.[88]

However, a court may not be able to harmonize Section 202(c) of the FPA and the CAA amendments in the more likely event that DOE orders a generating facility to operate such that it violates the NAAQS.[89] In such a scenario, courts will apply two basic principles of statutory interpretation: (1) the more recent statute controls, and (2) the more specific statute controls.

Congress amended the CAA in 1970 to implement the NAAQS. In 1935, Congress enacted Sections 202, 207, and 309 of the FPA. Based on these facts, a court could determine that the CAA amendments repealed by implication the conflicting

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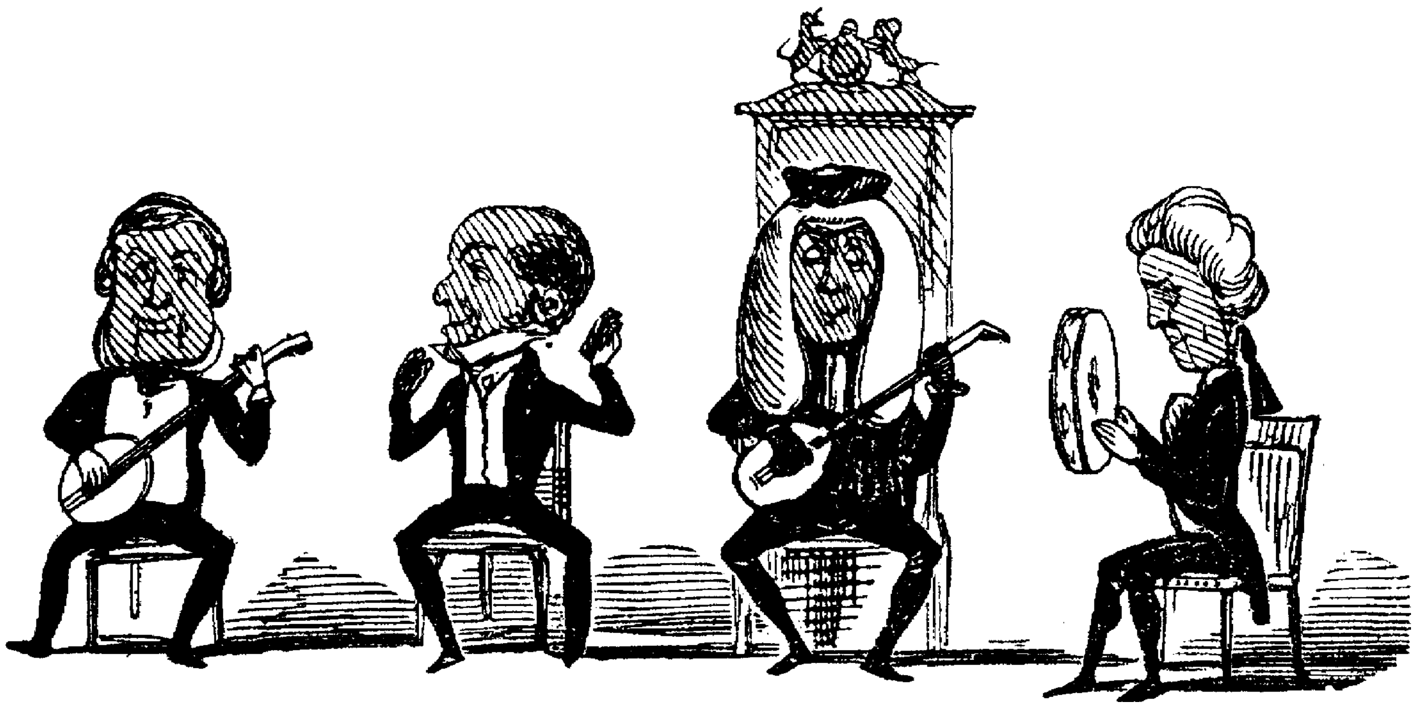

There needs to be cooperation among the federal agencies to create a stable and predictable regulatory environment.

provisions of the FPA.[90] However, courts disfavor a finding that a statute was repealed by implication and will look to determine whether the legislative intent to repeal was clear and manifest.[91] Here, such a determination would be unlikely because there is no evidence that Congress intended the CAA amendments to repeal any conflicting provision of the FPA.

Moreover, a more specific statute will control over a more general one.[92] The more specific statute may even take priority over another statute enacted by Congress more recently.[93] Here, both statutes require specific directives to be applied to individual generating facilities. The CAA calls for EPA to regulate generating facilities and mandate compliance with the NAAQS. The FPA, on the other hand, provides the authority to require certain plants to operate for reliability purposes as directed by DOE. Thus, while both statutes provide specific directives, it is not unlikely that a court could find that Section 202(c) of the FPA supersedes the CAA.

Regardless of whether the CAA or the FPA (Section 202(c) and/or Section 207) controls, there needs to be cooperation among the federal agencies to create a stable and predictable regulatory environment at a minimum and more preferably, a comprehensive solution to prevent this conflict from occurring in the first place.■

Endnotes:

1. 16 U.S.C. § 824a(c).

2. *See* 42 U.S.C. § 7151(b).

3. 10 C.F.R. § 205.371.

4. *Id.*

5. 16 U.S.C. § 824f.

6. *District of Columbia Public Service Commission*, 114 FERC ¶ 61,017 at P 2 (2006).

7. *See, e.g., Arkansas Public Service Commission v. Entergy Service, Inc. et al.*, 119 FERC ¶ 61,223 (2007).

8. William L. Massey, Robert S. Fleishman and Mary J. Doyle, *Reliability-Based Competition in Wholesale Electricity: Legal and Policy Perspective*, 25 Energy L.J. 319, 329 (2005).

9. 16 U.S.C. § 824f.

10. 16 U.S.C. § 824a(c).

11. 16 U.S.C. § 825h.

12. *New England Power Co. v. Fed. Power Comm.*, 467 F.2d 425, 430 (D.C. Cir. 1972).

13. *Niagara Mohawk Power Corp. v. Fed. Reg. Energy Comm.*, 379 F.2d 153, 158 (D.C. Cir. 1967).

14. 42 U.S.C. § 7409.

15. 42 U.S.C. § 7410.

16. *See, e.g., Her Majesty the Queen v. City of Detroit*, 874 F.2d 332 (9th Cir. 1989) (holding that once a SIP is approved by the EPA, its requirements become federal law and are fully enforceable in federal court).

17. 42 U.S.C. § 7506(c)(1).

18. *Id.*

19. *See* 40 C.F.R. § 51.853(b) – (c).

20. 40 C.F.R. § 51.853(c).

21. *Id.* §§ 51.853(d)(2), (e).

22. 42 U.S.C. § 7410 (f).

23. *City of Seabrook v. Costle*, 659 F.2d 1371 (5th Cir. 1981) (''*Seabrook*''); *see also Yakima v. Surface Transp. Bd.*, 46 F.Supp. 2d 1092 (E.D. Wa. 1999).

24. 42 U.S.C. § 7412(n)(1).

25. 65 Fed. Reg. 79826-27 (Dec. 20, 2000).

26. *New Jersey v. EPA*, 517 F.3d 574, 583 (D.C. Cir. 2008).

27. American Nurses Association, Chesapeake Bay Foundation, Inc., Conservation Law Foundation, Environment America, Environmental Defense Fund, Izaak Walton League of America, Natural Resources Council of Maine, Natural Resources Defense Council, Physicians for Social Responsibility, Sierra Club, The Ohio Environmental Council, and Waterkeeper Alliance, Inc. (Civ. No. 1:08-cv-02198 (RMC)), *at:* http://www.epa.gov/ttn/atw/utility/consentfnl.pdf.

28. Note that the original date of Nov. 16, 2011, was modified by consent of the parties, as described in paragraph 7(b). *Id.*

29. 42 U.S.C. § 7412 (d)(3).

30. 42 U.S.C. § 7412 (i)(3).

31. *Id.*

32. 42 U.S.C. § 7412 (i)(4).

33. 42. U.S.C. § 7604 (a).

34. DOE Order 202-02-1, Order Pursuant to Section 202(c) of the Federal Power Act (Aug. 16, 2002).

35. DOE Order 202-03-1, Order Pursuant to Section 202(c) of the Federal Power Act (Aug. 14, 2003); DOE Order 202-03-2, Order Pursuant to Section 202(c) of the Federal Power Act (Aug. 28, 2003).

36. *District of Columbia Public Service Commission*, DOE Order 202-05-3 at 2–3 (Dec. 20, 2005), *at* http://www.gc.doe.gov/sites/prod/files/oeprod/DocumentsandMedia/mirant_122005_2.pdf (hereinafter ''2005 DOE Order'').

37. *Id.* at 1.

38. *Id.* Mirant subsequently resumed operating one unit for 16 hours of each 24-hour period prior to DOE's order that it released on Dec. 20, 2005. Both EPA and VDEQ acknowledged that this minimal operation of the station did not result in NAAQS exceedances. *Id.* at 3.

39. Emergency Petition and Complaint of the District of Columbia Public Service Commission, Docket Nos. EO-05-01 (DOE), EL05-145-000 (FERC) (filed Aug. 24, 2005).

40. 2005 DOE Order at 6. As an example of the potential ramifications of a blackout, Pepco stated that ''within 24 hours of the loss of electric supply, Blue Plains will have no option but to release untreated sewage directly into the Potomac River.'' *Id.* at 4.

41. *District of Columbia Public Service Commission*, 114 FERC ¶ 61,017 (2006).

42. 2005 DOE Order at 5, 8–9.

43. Reliability Technical Conference, Docket No. AD12-1-000, *et al.*, Speaker Materials of Debra Raggio, GenOn Energy (filed Nov. 25, 2011), Attachment D, *Mirant Potomac River LLC*, Docket No. CAA-03-2006-0163DA, Administrative Compliance Order by Consent (June 1, 2006); EPA, Press Release, EPA Issues Administrative Order to Mirant Potomac River—Order Sets Schedule for Mirant to Comply with Clean Air Standards (June 2, 2006).

44. Reliability Technical Conference, Docket No. AD12-1-000, *et al.*, Speaker Materials of Debra Raggio, GenOn Energy (filed Nov. 25, 2011), Attachment D, *Mirant Potomac River LLC*, Docket No. CAA-03-2006-0163DA, Administrative Compliance Order by Consent at 14 (June 1, 2006).

45. *See* Reliability Technical Conference, Docket No. AD12-1-000, *et al.*, Speaker Materials of Debra Raggio, GenOn Energy at 5–6 (filed Nov. 25, 2011), Attachments E and F.

46. *See Notice of Issuance of Emergency Orders Under Section 202(c) of the Federal Power Act*, 65 Fed. Reg. 82,989 (Dec. 29, 2000); *see also* DOE Order, Order Pursuant to Section 202(c) of the Federal Power Act (Jan. 11, 2001).

47. *San Diego Gas & Elec. Co. v. Sellers of Energy & Ancillary Servs.*, 95 FERC ¶ 61,355 at 61,357 (2001). The must-offer obligation stemmed from an investigation into the reasonableness of rates for the sale of electric energy in the CAISO and PX spot markets by FERC pursuant to its authority under Section 206 of the FPA.

48. *Id.*

49. *San Diego Gas & Elec. Co. v. Sellers of Energy & Ancillary Servs.*, 96 FERC ¶ 61,117 at 61,448 (2001) (''In sum, in order to be exempted from the must offer requirement, a generator must demonstrate that running its unit violates a permit, would result in a criminal or civil violation or penalties, or would result in QF units violating their contracts or losing their QF status. In lieu of submitting a presentation such as that filed by Mirant, a generator may obtain a declaratory order from an appropriate court finding that the generator's compliance with the must offer requirement will result in a violation of its permit.'').

50. *See* Reliability Technical Conference, Docket No. AD12-1-000, *et al.*, Speaker Materials of Debra Raggio, GenOn Energy at 4 (filed Nov. 25, 2011).

51. 76 Fed. Reg. 48298 (August 8, 2011) (hereinafter ''CSAPR'').

52. CSAPR at 48,211.

53. Revisions to Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone, 76 Fed. Reg. 63,860; Federal Implementation Plans for Iowa, Michigan, Missouri, Oklahoma, and Wisconsin and Determination for Kansas Regarding Interstate Transport of Ozone, Docket ID: EPA-HQ-OAR-2009-0491 (Dec. 17, 2011) (to be codified at 40 C.F.R. parts 52 and 97).

54. EPA, Cross-State Air Pollution Rule, Reducing Air Pollution Protecting Public Health, *presentation* (Dec. 15, 2011) (*at:* http://www.epa.gov/airtransport/pdfs/CSAPRPresentation.pdf).

55. CSAPR at 48,279.

56. *See* EME Homer City Generation, L.P., *et al.* v. EPA, No. 11-1302 (D.C. Cir. Dec. 30, 2011) (order granting requested stay).

57. CSAPR at 48, 211.

58. National Emission Standards for Hazardous Air Pollutants from Coal and Oil fired Electric Utility Steam Generating Units, Docket ID EPA-HQ-OAR-2009-0234, pre-publication version, (*to be codified at* 40 C.F.R. Part 63) (hereinafter ''MATS'').

59. EPA FACT SHEET: Mercury and Air Toxics Standards, ADJUSTMENTS FROM PROPOSAL TO FINAL, Dec. 21, 2011; MATS at 630.

60. Comments of the Utility Air Research Group on EPA's National Emission Standards for Hazardous Air Pollutants from Coal and Oil-Fired Electricity Steam Generating Units, at 251, Docket EPA-HQ-OAR-2009-0234 (Aug. 4, 2011).

61. Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units – Final Report to Congress, EPA, (Feb. 1998), *at:* http://www.epa.gov/ttn/atw/combust/utiltox/eurtc1.pdf.

62. *See* North American Electric Reliability Corporation, 2010 Special Reliability Scenario Assessment: Resource Adequacy of Potential U.S. Environmental Regulations (Oct. 2010), *at* http://www.nerc.com/files/EPA_Scenario_Final.pdf (hereinafter ''NERC Report'').

63. EPA FACT SHEET: Mercury and Air Toxics Standards, ADJUSTMENTS FROM PROPOSAL TO FINAL, Dec. 21, 2011.

64. MATS at 568.

65. *Id.*

66. *See* Memorandum for the Administrator of the Environmental Protection Agency, Flexible Implementation for the Mercury and Air Toxics Standards Rule, from Barack Obama (Dec. 21, 2011) (hereinafter ''Presidential Memo''); Memorandum, The Environmental Protection Agency's Enforcement Response Policy For Use Of Clean Air Act Section 113(a) Administrative Orders In Relation To Electric Reliability And The Mercury And Air Toxics Standard, from Cynthia Giles (December 16, 2011) (''Enforcement Memo'').

67. Presidential Memo at 2.

68. Fed. Reg. 35,128 (June 21, 2010).

69. Fed. Reg. 63,252 (Oct. 12, 2011).

70. EPA Eyes Late 2012 For Coal Ash Reuse Risk Analysis Ahead Of Final Rule, Inside EPA (Dec. 9, 2011) (quoting Administrator Jackson, ''I think it's going to be towards the end of the year.'').

71. Fed. Reg 43,230 (July 20, 2011).

72. See Settlement Agreement Among the United States Environmental Protection Agency, Plaintiffs in *Cronin, et al. v. Reilly*, 93 Civ. 314 (LTS(SDNY), and Plaintiffs in *Riverkeeper, et al. v. EPA*, 06 Civ. 12987 (PKC)(SDNY) (Nov. 22, 2010) as subsequently amended (available at: http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/phase2/upload/316bsettlement.pdf).

73. Reliability Technical Conference, Docket No. AD12-1-000, *et al.*, PJM, Interconnection, L.L.C. Testimony of Mike Kormos at 3 (filed Nov. 22, 2011) (hereinafter ''PJM Testimony'').

74. *Id.* To date, PJM has not identified any ''overarching reliability impacts associated with potentially retiring units that cannot be resolved with transmission upgrades within the four year period allowed by the proposed MATS rule.'' *Id.* at 8.

  doi:/10.1016/j.tej.2012.01.001

75. *See, e.g.*, NERC Report (finding 33-70 GW of coal-fired generation to be retired by 2015); *see also* Edison Electric Institute, Potential Impacts of Environmental Regulation on the U.S. Generation Fleet (Jan. 2011), *at* http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2011IRP/EEIModelingReportFinal-28January2011.pdf (finding 16-75 GW of unplanned coal-fired generation retirements by 2015) (hereinafter ''EEI Report''); *Fitch: New EPA Rule Likely to Speed Plant Retirements*, Wall St. J. (Dec. 23, 011) (citing Fitch Ratings, Time to Retire? II The Update to Coal Plant Retirements (Nov. 17, 2011)) (indicating up to 83 GW of coal-fired generation may be retired due to various EPA rules).

76. Joint Comments of the Electric Reliability Council of Texas, the Midwest Independent Transmission System Operator, the New York Independent System Operator, PJM Interconnection, LLC, and the Southwest Power Pool, Docket Nos. EPA-HQ-OAR-2009-0234, *et al.* (Oct. 21, 2011), *at* http://pjm.com/~/media/documents/other-fed-state/20110804-epa-hq-oar-2009-0234-iso-rto.ashx (''Joint RTO Comments'').

77. *Id.* at 5.

78. *Id.* at 6.

79. *See* Enforcement Memo.

80. *See* Enforcement Memo; Presidential Memo.

81. Enforcement Memo at 5–6.

82. *Id.* at 6.

83. *See* Press Release, Sen. Murkowski (R-Alaska), Reliability Concerns Warrant Careful Review of Utility MACT Rule, (Dec. 21, 2011), *at* http://energy.senate.gov/public/index.cfm?FuseAction=PressReleases.Detail&PressRelease_id=821625c0-c4aa-4c79-8253-34a510a1bff6& Month=12&Year=2011&Party=1.

84. *See for example* Exelon Generation Company, LLC, Order Accepting and Suspending Tariff Filing at para. 30–31, 132 FERC ¶ 61,219 (Sep. 16, 2010).

85. *See, e.g.*, *Blue Chip Stamps. v. Manor Drug Stores*, 421 U.S. 723 at 756 (1975) (''the starting point in every case involving construction of a statute is the language itself'').

86. *See, e.g.*, *Watt v. Alaska*, 451 U.S. 259, 267 (1981) (courts will read conflicting statutes ''to give effect to each if [courts] can do so while preserving their sense and purpose''); *Morton v. Mancari*, 417 U.S. 535 at 550–551 (1974) (''the courts are not at liberty to pick and choose among congressional enactments, and when two statutes are capable of co-existence, it is the duty of the courts, absent a clearly expressed congressional intention to the contrary, to regard each as effective'').

87. *See, e.g.*, *Nat'l Ass'n of Home Builders v. Defenders of Wildlife*, 551 U.S. 644, 661–669 (2007) (holding that the Endangered Species Act's ''no-jeopardy duty only applies to discretionary agency actions and does not attach to actions . . . that an agency is *required* by statute to undertake once certain specified triggering events have occurred''); *Flint Ridge Dev. Co. v. Scenic Rivers Ass'n*, 426 U.S. 776 at 778 (1976) (where a clear and unavoidable conflict in statutory authority exists, ''NEPA must give way''); *see also Operation of the Mo. River Syst. Litigation*, 421 F.3d 618, 630 (8th Cir. 2005) (stating that environmental statutes ''do not apply where they would render an agency unable to fulfill a non-discretionary statutory purpose. . .'').

88. *See Nat'l Wildlife Federation v. US Army Corps of Engineers*, 384 F.3d 1163, 1179 (9th Cir. 2004) (holding that the construction and operation of dams in accordance with Congressional mandates did not violate Clean Water Act provisions despite causing exceedances); *Platte River Whooping Crane Critical Habitat Maintenance Trust v. FERC*, 962 F.2d 27 (D.C. Cir. 1992) (holding that the Endangered Species Act does not alter the scope of FERC's authority under the FPA).

89. With respect to the Potomac River Generating Station, the VDEQ argued that the CAA and the FPA did not conflict because both DOE and FERC must consider and, if necessary, mitigate proposed actions under the National Environmental Policy Act (NEPA). Motion to Intervene and Protest of Virginia Department of Environmental Quality Director Robert G. Burnley, Docket No. EL05-145-000 (filed Aug. 29, 2005). However, this argument failed to take into account the fact that DOE orders issued in response to emergency situations are exempt from NEPA. *See* 10 C.F.R. 1021.343. Because DOE can only order a generating facility to operate in an emergency situation, NEPA will not apply.

90. *See Watt*, 451 U.S. at 266-67 (citing 2A C. Sands, Sutherland on Statutes and Statutory Construction Section 51.02 (4th ed. 1973)).

91. *Posadas v. National City Bank*, 296 U.S. 497, 503 (1936) (''the cardinal rule is that repeals by implication are not favored'').

92. *See Bulova Watch Co. v. United States*, 365 U.S. 753, 758 (''it is familiar law that a specific statute controls over a general one 'without regard to priority of enactment'''); *see also* 2B Norman J. Singer, Sutherland Statutes and Statutory Construction Section 51.05 (6th ed. 2000).

93. *Morton*, 417 U.S. at 550–551 (''Where there is no clear intention otherwise, a specific statute will not be controlled or nullified by a general one, regardless of the priority of enactment.'').

  doi:/10.1016/j.tej.2012.01.001