Greenhouse Gas Emission Reductions From Existing Power Plants Under Section 111(d) of the Clean Air Act:

Options to Ensure Electric System Reliability

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Introduction and Executive Summary

In June 2014, the U.S. Environmental Protection Agency ("EPA") is expected to propose guidance to the states for reducing greenhouse gas ("GHG") emissions from existing fossil-fuel power plants. Final guidance is expected a year later, with requirements that each state develop and submit a state implementation plan ("SIP") for how the state would prefer to achieve such emissions reductions at the power plants in its state. While the Clean Air Act's Section 111 identifies many criteria for setting the emissions standard and for states' development of SIPs to achieve it, an important additional objective not mentioned in the Act but still important for the nation is assuring that such plans will not jeopardize electric system reliability.

This paper addresses whether EPA's actions to regulate GHG emissions from existing power plants will give rise to electric system reliability problems,[1] and explains why it will not.

Industry participants have often raised concerns about potential electric system reliability impacts from major new EPA regulations affecting power plants. This was a major issue in 2010 to 2012, for example, in many parties' comments on EPA's proposals to control mercury and air toxic emissions (the "MATS" rule). Reliability concerns have already been raised in relation to EPA's upcoming regulation of GHG emissions from existing power plants.[2]

Electric system reliability:

"The degree to which the performance of the elements of the electrical system results in power being delivered to consumers within accepted standards and in the amount desired. Reliability encompasses two concepts, adequacy and security. Adequacy implies that there are sufficient generation and transmission resources installed and available to meet projected electrical demand plus reserves for contingencies. Security implies that the system will remain intact operationally (i.e., will have sufficient available operating capacity) even after outages or other equipment failure. The degree of reliability may be measured by the frequency, duration, and magnitude of adverse effects on consumer service."

Energy Information Administration.

[1] The North American Electric Reliability Corporation ("NERC") further explains the adequacy component of reliability: "The ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements." In this paper, I focus on reliability in the bulk-power system, which NERC defines as: "(A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and (B) electric energy from generation facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy….The bulk power electric system is routinely planned and operated so as to perform reliably under normal and abnormal conditions." http://www.nerc.com/files/glossary_of_terms.pdf.

[2] See, for example, hearings held on November 14, 2013, before the House Energy and Commerce Subcommittee on Energy and Power, and comments made by panelists at the February 12, 2014 meeting of the National Association of Regulatory Utility Commissioners ("NARUC").

Historically, the reliability red flag[3] has tended to be raised with regard to concerns that compliance with a new environmental rule would require a large portion of generating capacity to be simultaneously out of service to add control equipment, to retire permanently, or otherwise to become unavailable to produce power.[4] To date, implementation of new environmental rules has not produced reliability problems, in large part because the industry has proven itself capable of responding effectively. A very mission-oriented industry, composed of electric utilities, other grid operators, non-utility energy companies, federal and state regulators, and others, has taken a wide variety of steps to ensure reliability.[5]

Regarding the upcoming EPA regulations of GHG emissions from existing power plants, reliability concerns are misplaced. It is broadly understood – including by President Obama[6]

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[3] In recent years, many Congressional hearings have addressed the implications of EPA regulations for electric system reliability. For example: hearings before the House Energy and Commerce Subcommittee on Energy and Power (December 5, 2013; May 9, 2012; and September 14, 2011); the November 1, 2011 hearing before the House Oversight and Government Reform Committee; and the June 30, 211 hearing before the Senate Environment and Public Works Subcommittee on Clean Air and Nuclear Safety. In 2010/2011, NERC published major assessments of electric system reliability and EPA regulations. .

[4] This, for example, was how the issue came up in discussions of EPA's acid rain regulations in the early 1990s and in proposals for how Northeast states would reduce sulfur dioxide ("SO2"), and nitrogen oxides ("NOx") emissions from existing power plants. In such cases, key questions were whether the electric industry (and its supply chains) could respond in a timely way to regulatory requirements while also ensuring that the lights stay on at all times in every part of the affected regions of the U.S. This was the framing of reliability concerns in recent years when EPA agency proposed the combination of regulations affecting cross-state transport of NOx (e.g., the "Cross-State Air Pollution Rule" ("CSAPR") and toxic air pollution (e.g., the MATS rule)).

[5] For example, the Federal Energy Regulatory Commission ("FERC") has authority under the Energy Policy Act of 2005 to ensure reliability in the bulk power systems, and has delegated to the NERC (as the National Reliability Organization) the responsibility for setting reliability standards. For decades, states have supervised – and continue to do so – utilities and others' planning for long-term resource adequacy. I previously described these processes, norms, requirements, and other elements of the mission-oriented culture of the industry: "The U.S. electric industry has a proven track record of doing what it takes to provide the reliable power supplies. Regulated electric utilities, competitive electric companies, grid operators, and regulators have a strong mission orientation, along with regulatory requirements, which together ensure that reliable electricity supply is a priority. For many decides, the U.S. electric industry has developed institutions, operating and planning requirements, system plans, operating approaches, emergency response protocols, and billions of dollars of investment to assure reliable electricity supply. The industry is keenly aware that the American economy and standard of living depend upon reliable power supplies…. With some notable exceptions, utilities and other electric companies and their workers, investors, and suppliers, have provided what Americans take for granted and what public officials insist upon: that electricity be reliably available around the clock, with increasing levels of environmental performance to assure worker and community safety and public health. ….The electric industry has responded well in prior periods (such as the mid-1990s) when Clean Air Act requirements led to investments in new pollution-control equipment and new additions to generating capacity. There were no reliability problems arising from those actions, in spite of concerns raised that there would be equipment shortages and difficulties adding control equipment on so many power plants in a constrained period of time." Testimony of Susan Tierney, Before the U.S. Senate Environment and Public Works Committee. Subcommittee on Clean Air and Nuclear Safety, June 30, 2011 (Oversight Hearing: Review of EPA Regulations Replacing the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR)).

[6] The June 35, 2013 "Presidential Memorandum -- Power Sector Carbon Pollution Standards" states that "In developing standards, regulations, or guidelines … {EPA] shall ensure, to the greatest extent possible, that you: …(v) ensure that the standards are developed and implemented in a manner consistent with the continued provision of reliable and affordable electric power for consumers and businesses…"

and the EPA's Administrator[7] – that regulatory actions to reduce threats to public health and the environment from power generation cannot occur at the expense of reliable power supply.

Moreover, EPA will be relying on a portion of the Clean Air Act ("CAA") – Section 111(d) – to regulate GHG emissions from existing power plants. Section 111(d)'s regulatory framework creates an entirely different and potentially much wider set of compliance and implementation options compared to other recent federal regulatory initiatives applicable to the electric industry. Section 111(d)'s 'cooperative federalism' model provides for much more compliance flexibility and creativity than was possible for the many unit-specific regulations issued by EPA in the past two decades. This is core to understanding why EPA's regulation of GHG emissions from existing power plants will not jeopardize electric system reliability.

In the recent MATS rule, for example, EPA set uniform national standards to reduce emissions from different categories of existing coal- and oil-fired power plants. No trading or averaging is allowed across different generating stations. There is no possibility of purchasing credits resulting from over-compliance at other sources, or to credit emissions reductions resulting from end-use efficiency or zero-carbon energy sources.

By contrast with MATS, Section 111(d) inherently allows greater opportunities for different pathways to compliance. Section 111(d) relies on the SIP process. This means that EPA will provide states with guidance allowing considerable and wide-ranging latitude in how they plan to meet EPA's requirements. EPA's guidance will not likely impose a standard that must be met solely by actions taken at each affected unit. Rather, EPA is likely to establish standards specific to each state, based on the "degree of emission limitation achievable through the application of the best system of emission reduction," which may vary across states in light of their own particular circumstances. And in its SIP, each state will have flexibility to propose its own preferred actions to accomplish the targeted reductions, as long as the plan provides reductions across the facilities in the state that are at least as effective as EPA's approach.[8] This language "supports the use of market-based mechanisms" and other alternatives in ways that

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[7] See, for example: Statement of Gina McCarthy, Nominee for the Position of Administrator of the EPA, Before the Environment and Public Works Committee, U.S. Senate, April 11, 2013; Testimony of Gina McCarthy before the FERC, Reliability Technical Conference, Docket Number AD12-1-000, November 30, 2011.

[8] Section 111(d) directs EPA to "prescribe regulations which shall establish a procedure similar to that provided by section 110 under which each State shall submit to the Administrator a plan…." As explained in Section 110 (a)(2)(A) of the Act, a SIP shall (among other things), "(A) include enforceable emission limitations and other control measures, means, or techniques (including economic incentives such as fees, marketable permits, and auctions of emissions rights), as well as schedules and timetables for compliance, as may be necessary or appropriate to meet the applicable requirements of this chapter."

are not possible under the statutory language governing MATs, which required each affected generating station to have emissions at or below the allowed emissions rates.

If a state has concerns about the reliability implications of compliance with EPA guidance, the state can take that fact into account as it designs its SIP and its schedule/timetable for individual units' compliance so long as the overall emission reduction required by the guideline has a firm deadline and is achieved. For example, a state could propose plan elements that enable early action/compliance at some Section 111(d) generating units in exchange for allowing more time for others, or that allow for deeper reductions at one unit in exchange for lighter reductions at another. Thus, the inherent authority within Section 111(d) removes the reliability red flag in this case, as long as the EPA, the states, and the industry take appropriate and timely steps.

States may consider diverse options as they plan for cost-effective emissions reductions while also ensuring electric system reliability. Some of the options may take place "inside the fence" of generating units covered by Section 111(d), while others might focus more on interactions of those plants' emissions in light of changes in power demand, transmission and generation:

- *Inside the fence*: Examples include: heat-rate improvements; fuel switching; averaging of emissions within a single station; and changes to the operating permit of existing power plants to limit emissions over some averaging period.

- *Outside the fence:* Examples include: emission reductions achieved through changes in the overall dispatch of existing generating resources and/or level of demand on the system: emission-averaging among multiple power plants; state carbon budgets with an emissions cap-and-trade program; multi-state electric-system dispatch practices of grid operators; demand-side reductions; adoption of clean energy standards; and/or transmission upgrades to open up access to underutilized, low-carbon facilities.

Other factors also allow for cost-effective emissions reductions at Section 111(d) units in ways that do not adversely affect system reliability. A significant amount of existing generating capacity is underutilized. For example, output at natural-gas fired combined-cycle power plants averaged approximately 50 percent in 2012. There is the potential to reduce overall demand through energy efficiency, thus reducing the need to dispatch plants with relatively high emission rates. There is potential to add additional low or zero-carbon electricity supply (e.g., wind and solar; combined heat and power; nuclear uprates). Actions also can be taken to extend the life of, or increase the output from, well-performing generating units that produce no emissions at the facility (e.g., hydroelectric resources, nuclear plants). These various resources offer significant flexibility and optionality to states as they prepare a SIP suited to their own circumstances and conditions (including reliability concerns).

As they develop SIPs in response to the EPA's Section 111(d) guidance, the states start from a position of great diversity in their electric power industries. These differences show up in the character of the power plants located in each state, the electric industry structure, the CO_2 emissions from existing power plants, renewable energy potential, reliance on in-state versus out-of-state power resources, the outlook for demand growth, mix of public policies affecting power plants, and many other differences. This will likely lead to varied approaches in SIP designs. (See the Appendix 2 for the generating units in each state that are directly affected by Section 111(d) requirements, along with information about other generating resources and their capacity factors in 2012.)

To envision how differently situated states might shape their compliance strategies to assure both electric system reliability and compliance with upcoming EPA guidance, this paper concludes with a handful of examples representing ways that states could consider shaping their SIPs to suit their own conditions. The examples address options for states with traditionally regulated electric industries, and for states whose electric companies participate in an organized interstate wholesale electric market managed by a regional transmission organization ("RTO"). The GHG control options include: inter-facility emissions trading for plants owned by a common owner in a single state or in multiple states with traditional electric industry structure; inter-state trading among plants owned by multiple owners in traditionally regulated states; reliance on a state-wide emissions budget combined with other mechanisms to allow emissions averaging across plants located within a single-state or multi-state RTO; and use of collateral programs to support cost-effective emissions reductions (such as clean energy standards, renewable portfolio standards, energy efficiency programs, transmission enhancements, and others). All of these provide extensive opportunities for innovative SIP elements that can accommodate cost-effective environmental compliance, alignment with economic principles underpinning electric industry structure and market design, while maintenance of electric system reliability.

The bottom line: there is no reasonable basis to anticipate that EPA's guidance, the states' SIPs and the electric industry's compliance with them will create reliability problems for the power system, as long as EPA and the states plan appropriately and take timely actions to assure electric-system reliability in their plans. Section 111(d) affords states considerable latitude to mitigate and otherwise resolve reliability concerns.

To explain how I reached this conclusion, this paper covers the following topics:

- the federal/state regulatory framework under Section 111(d) of the CAA;
- how Section 111(d)'s reliance on the preparation of SIPs makes this regulatory framework inherently different from other recent environmental regulations affecting existing power plants, and provides more compliance options and greater flexibility;
- the types of power plants directly affected by the GHG reduction policies, with differences among fleets in various regions of the country;
- conditions in the electric industry (such as the outlook for demand, fuel prices, plant additions and retirements) that set the stage for the industry's future compliance with GHG regulations for existing plants;
- the breadth of tools that may be available to the states as they consider what to include in their SIPs;
- the factors that states may take into account to assure electric system reliability as part of their compliance strategies;
- examples of ways to design compliance strategies in different industry contexts; and
- the overall implications of Section 111(d) compliance for maintaining electric system reliability.

Regulating GHG Emissions from Existing Power Plants under Section 111(d) of the Clean Air Act

Under the CAA, the control of GHG emissions from existing power plants fits within a larger framework in which EPA regulates air pollution from mobile and stationary sources. Section 111(d) sets forth the process through which EPA will regulate GHG emissions from existing power plants, which account for 40 percent of total CO_2 emissions in the U.S.,[9] and one out of every 15 tons of CO_2 emitted anywhere in the world.[10]

Much has been written about the overall framework under which GHG emissions may be regulated under the CAA.[11] These analyses depict the process now underway:

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[9] Based on 2011 data, the most recent available in the EPA's "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2011," April 12 2013, Table 2-3 (Recent Trends in U.S. Greenhouse Gas Emissions and Sinks) and Table 2-4 (Emissions from Energy).

[10] The U.S. emitted 5,433,056 kt of CO_2, out of the total 33,615,389 kt of CO_2 emitted globally in 2010. The U.S.'s CO_2 emissions were 16 percent of the global amount. http://data.worldbank.org/topic/climate-change. Assuming electric power accounts for 40 percent of U.S. CO_2 emissions (from the EPA GHG Inventory data), then electric power production in the U.S. accounted for 6.5 percent of global CO_2 emissions in 2010.

[11] For example, see: Dan Lashof, et. al., "Cleaner and Cheaper: Using the Clean Air Act to Sharply Reduce Carbon Pollution from Existing Power Plants, Delivering Health, Environmental, and Economic Benefits," NRDC, March 2014; Clean Air Task Force, "Power Switch: An Effective, Affordable Approach to Reducing Carbon Pollution from Existing Fossil-Fueled Power Plants," February 2014, with accompanying analysis (Bruce Phillips, The Northbridge Group," Alternative Approaches for Regulating Greenhouse Gas Emissions from Existing Power Plants under the Clean Air Act: Practical Pathways to Meaningful Reductions," February 27, 2014); Comments of the Attorneys General of New York, California, Massachusetts, Connecticut, Delaware, Maine, Maryland, New Mexico, Oregon, Rhode Island, Vermont, Washington, and the District of Columbia on the Design of a Program to Reduce Carbon Pollution from Existing Power Plants, December 16, 2013; White Paper to EPA from 18 State Attorneys General, "Perspective of 18 States on Greenhouse Gas Emission Performance Standards for Existing Sources under § 111(d) of the Clean Air Act," November 2013; Megan Ceronsky and Tomas Carbonell, "Section 111(d) of the Clean Air Act: The Legal Foundation for Strong, Flexible & Cost-Effective Carbon Pollution Standards for Existing Power Plants," Environmental Defense Fund, October 2013; Christopher Van Atten, "Structuring Power Plant Emissions Standards Under Section 111(d) of the Clean Air Act – Standards for Existing Plants," MJ Bradley & Associates, October 2013; James McCarthy, "EPA Standards for Greenhouse Gas Emissions from Power Plants: Many Questions, Some Answers," Congressional Research Service, September 30, 2013; National Climate Coalition, "Using EPA Clear Air Act Authority to Build a Federal Framework for State Greenhouse Gas Reduction Programs," September 2013; Scott Schang, ed., *Old Laws, New Tricks: Using the Clean Air Act to Curb Climate Change* (Environmental Law Institute, August 19, 2013); Kyle Danish, Stephen Fotis, Doug Smith, Ilan Gutherz, "EPA Regulation of Greenhouse Gas Emissions from Existing Power Plants: Issues and Options," Van Ness Feldman, June 27, 2013; Daniel A. Lashof, et. al., "Closing the Power Plant Carbon Pollution Loophole: Smart Ways the Clean Air Act Can Clean Up America's Biggest Climate Polluters," March 2013; Nicholas Bianco and Franz Litz, "Reducing Greenhouse Gas Emissions in the United States: Using Existing Federal Authorities and State Action," World Resources Institute, February 2013; Jeremy Tarr, Jonas Monast and Tim Profeta, "Regulating Carbon Dioxide under Section 111(d) of the Clean Air Act: Options, Limits, and Impacts," Nicholas Institute, Duke University, January 2013; Georgetown Climate Center, "Issue Brief for the States: EPA's Forthcoming Performance Standards for Regulating Greenhouse Gas Pollution from Power Plants (Clean Air Action Section 111)," September 2011; Gregory E. Wannier, Jason A. Schwartz, Nathan Richardson, Michael A. Livermore, Michael B. Gerrard, and Dallas Burtraw, "Prevailing Academic View on Compliance Flexibility under § 111 of the Clean Air Act," Resources for the Future, July 2011; Pew Center on Global Climate Change, "GHG New Source Performance Standards for the Power Sector: Options for EPA and the States," March 17, 2011.

- The U.S. Supreme Court's 2007 holding that "greenhouse gases fit well within the [Clean Air] Act's capacious definition of 'air pollutant'."[12]
- The EPA Administrator's finding in 2009 that current and projected concentrations of GHGs "in the atmosphere threaten the public health and welfare of current and future generations."[13]
- The President's 2009 pledge at the United Nations Climate Change Conference that by 2020, America would reduce its GHG "emissions in the range of 17 per cent by 2020" compared with 2005 levels.[14]
- The President's 2013 Climate Action Plan and Presidential Memorandum directing the EPA to take steps under Section 111(d) authority to reduce carbon pollution from existing power plants,[15] and to do so through engaging directly with the states ("as they will play a central role in establishing and implementing standards for existing power plants") and other stakeholders.[16]

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[12] 549 U.S. 497 (2007).

[13] 74 Fed. Reg. 66496 (December 15, 2009) (Environmental Protection Agency, Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act).

[14] White House Press Release, Remarks by the President in the Morning Plenary Session of the United Nations Climate Change Conference, Copenhagen, December 18, 2009.

[15] The President's Climate Action Plan, June 2013; White House, Presidential Memorandum -- Power Sector Carbon Pollution Standards, June 25, 2013.

[16] "Carbon Pollution Regulation for Modified, Reconstructed, and Existing Power Plants. To ensure continued progress in reducing harmful carbon pollution, I direct you to use your authority under sections 111(b) and 111(d) of the Clean Air Act to issue standards, regulations, or guidelines, as appropriate, that address carbon pollution from modified, reconstructed, and existing power plants and build on State efforts to move toward a cleaner power sector." White House, Presidential Memorandum -- Power Sector Carbon Pollution Standards, June 25, 2013. The Memorandum also directs that EPA "(ii) consistent with achieving regulatory objectives and taking into account other relevant environmental regulations and policies that affect the power sector, tailor regulations and guidelines to reduce costs; (iii) develop approaches that allow the use of market-based instruments, performance standards, and other regulatory flexibilities; (iv) ensure that the standards enable continued reliance on a range of energy sources and technologies; (v) ensure that the standards are developed and implemented in a manner consistent with the continued provision of reliable and affordable electric power for consumers and businesses; and (vi) work with the Department of Energy and other Federal and State agencies to promote the reliable and affordable provision of electric power through the continued development and deployment of cleaner technologies and by increasing energy efficiency, including through stronger appliance efficiency standards and other measures."

How does Section 111(d) of the CAA work?

Regulation of one third of the nation's GHG emissions (i.e., from existing fossil power plants) will take place through a portion of the CAA that is used infrequently. Section 111(d) only applies to pollutants (like GHGs) not regulated elsewhere in the law. Most air pollutants emitted from power production – including emissions of sulfur dioxide ("SO_2"), nitrogen oxides ("NO_x"), and air toxics like mercury – are specifically covered by other parts of the CAA. The electric industry, the states and many other stakeholders have become familiar with regulatory approaches related to those other pollutants over several decades.

Section 111(d) has only been used to control emissions for five categories of existing sources of emissions[17] and never for a pollutant that is so pervasive (as CO_2) in the U.S. and globally. Thus it is thus relatively 'new' to the EPA, as well as to the regulated industry and the states.

Clean Air Act:

Section 111(d) Standards of performance for existing sources; remaining useful life of source [excerpts]

(1) The Administrator shall prescribe regulations which shall establish a procedure similar to that provided by section 110 under which each State shall submit to the Administrator a plan which (A) establishes standards of performance for any existing source for any air pollutant (i) for which air quality criteria have not been issued …, and (B) provides for the implementation and enforcement of such standards of performance. Regulations of the Administrator under this paragraph shall permit the State in applying a standard of performance to any particular source under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies.

Section 111(a) Definitions [excerpts] For the purposes of this section:

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

(See Appendix 1 for additional statutory language from Section 111 of the CAA)

That said, the upcoming regulatory process is not entirely unfamiliar to the states. Section 111(d) calls for EPA to use "a procedure similar to that provided by section 110." Section 110 is a well-established "cooperative federalism" framework that has been relied upon for decades to ensure that EPA's National

[17] Section 111(d) has been used previously for regulating: landfill gases from municipal solid waste landfills; acid mist from sulfuric acid plants; flourides from phosphate fertilizer plants; flourides from primary aluminum plants; and total reduced sulfur from kraft pulp plants. Source: "Overview presentation of Clean Air Act Section 111," http://www2.epa.gov/carbon-pollution-standards/what-epa-doing.

Ambient Air Quality Standards ("NAAQS") are met and maintained for six common air pollutants (known as 'criteria pollutants'). Under Section 110, "EPA uses its expertise to determine *what* the NAAQS should be, and the states are delegated the authority to determine *how* the NAAQS will be achieved."[18] In essence, the 'cooperative federalism' framework of Section 111(d) can be thought of one in which EPA identifies the destination (e.g., ambient air quality), and states determine what route they want to take to get there.[19] In the past, the states (typically through their state air regulatory agency) have developed SIPs to demonstrate how they will address ground-level ozone (smog), particulate emissions, SO_2, NOx, and other criteria pollutants to meet the national air standards.[20] Thus, state air regulators have considerable experience with such SIP processes.[21]

In various presentations, statements and other documents, EPA has provided strong indications of how it intends to move forward under the Section 111(d) framework. The process is expected to involve the following steps and elements:[22]

- **EPA Guidance**: EPA issues guidance to the states with respect to the "best system of emissions reductions" ("BSER") from existing power plants. This guidance will likely establish the target CO_2 tonnage reductions, or reductions in CO_2 emission rates per megawatt-hour ("MWh"), that each individual state must achieve at affected generating units through its SIP.

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[18] Jonas Monast, Tim Profesta, Brooks Rainey Pearson, and John Doyle, "Regulating Greenhouse Gas Emissions from Existing Sources: Section 111(d) and State Equivalency," 42 ELR 10206, March 2012 (hereinafter "Monast et. al. (2012)").

[19] Susan Tierney, "Section 111(d) of the Clean Air Act: Drivers of Power Sector CO_2 Reductions," presentation to the Bipartisan Policy Center Workshop on GHG Regulation of Existing Power Plants under the Clean Air Act: Policy Design and Impacts, December 6, 2013.

[20] The States "develop a general plan to attain and maintain the NAAQS in all areas of the country and a specific plan to attain the standards for each area designated nonattainment for a NAAQS. These plans, known as State Implementation Plans or SIPs, are developed by state and local air quality management agencies and submitted to EPA for approval." http://www.epa.gov/oar/urbanair/sipstatus/index.html

[21] See, for example, EPA's website that tracks the status of each state's SIP for each criteria pollutant. As is apparent there, SIPs include elements that are added or changed over time. http://www.epa.gov/oar/urbanair/sipstatus/reports/map_s.html.

[22] This description is drawn from various documents, including from the EPA's website and its "Overview presentation of Clean Air Act Section 111"(http://www2.epa.gov/carbon-pollution-standards/what-epa-doing); EPA Office of Air and Radiation, "Considerations in the Design of a Program to Reduce Carbon Pollution from Existing Power Plants," September 23, 2013 version (hereinafter "EPA Design Considerations 2013"); EPA, "Background on Establishing New Source Performance Standards (NSPS) Under the Clean Air Act," October 2013, http://www.epa.gov/region9/air/listening/BackgroundEstablishingNewSourcePerformanceStds.pdf; EPA, Office of Air Quality Planning and Standards ("OAQPS"), "Rulemaking for Greenhouse Gas Emissions from Electric Utility Steam Generating Units," Tribal Consultation, May 2011 (hereinafter "OAQPS GHG Presentation").

- Guidance will be developed through EPA's normal rulemaking process with a notice-and-comment period (including a Regulatory Impact Assessment), and with "binding requirements that states are required to address when they develop plans to regulate existing sources in their jurisdictions."
- The guidance will come first in proposed form (by June 1, 2014), and then in final form (by June 1, 2015).
- The Presidential Memorandum requests that EPA guidelines require that States submit to EPA their SIPs by no later than June 30, 2016.
- EPA's guidance will likely set the target reductions for states to use in developing their implementation plans with performance standards that apply to the power plants subject to Section 111(d) (the "affected sources" of GHG emissions). Consistent with prior Section 111(d) rules, "EPA believes that its guidelines should identify for sources and states the required level(s) of performance prior to plan submittal."[23] Based on prior EPA guidance under Section 111(d), the GHG guidance is likely to contain:[24]
    - A description of BSER that has been adequately demonstrated for a particular category of sources (taking into account feasibility, cost, emissions reductions, and technology development issues);[25] the degree of emission limitation achievable, costs and benefits, and environmental impacts of application; and a goal for reductions based on the BSER analysis.
    - No specific prescribed technologies that must be used to comply.

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[23] EPA Design Considerations 2013.

[24] Sources for these points: EPA, "Background on Establishing New Source Performance Standards (NSPS) Under the Clean Air Act," October 2013, http://www.epa.gov/region9/air/listening/BackgroundEstablishingNewSourcePerformanceStds.pdf; "Overview presentation of Clean Air Act Section 111"(http://www2.epa.gov/carbon-pollution-standards/what-epa-doing); OAQPS GHG Presentation; Monast et. al. (2012).

[25] Senior EPA officials have stated that the *particular* BSER the agency adopts for existing sources of GHG emissions will not be the same as the one it adopted for new power plants, although the BSER *criteria* EPA takes into account are similar. (See the statement of Acting Administrator for Air and Radiation Janet McCabe before the House Energy and Commerce Subcommittee on Energy and Power (November 14, 2013)). The application of the criteria to new versus existing power plants is what would lead to different BSER targets. In EPA's proposed Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units" (dated September 2013), EPA explains the factors that are to be considered in identifying the BSER: "For this rulemaking [under Section 111(b)], the following factors are key: feasibility, costs, size of emission reductions and technology. **Feasibility …**whether the system of emission reduction is technically feasible. **Costs…**whether the costs of the system are reasonable. **Size of emission reductions**…the amount of emissions reductions that the system would generate. **Technology**…whether the system promotes the implementation and further development of technology." Page 25 of the signed prepublication version of 40 CFR Part 60 [EPA-HQ-OAR-2013-0495; FRL-9839-4] RIN 2060-AQ91, EPA, Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units, September 20, 2013 (hereinafter "EPA 2013 Proposed GHG Standards for New EGUs").

    - A stated performance standard using a rate of allowed emissions that is met on a facility-by-facility basis (although EPA has discretion to set performance standards for classes of power plants based on an allowed rate of emissions (e.g., pounds of CO_2 per MWh) or a total mass of emissions (e.g., a CO_2 tonnage budget for a state)).[26]
    - Timelines for implementing its guidelines.
    - "Different guidelines or compliance times (or both)…for different sizes, types, and classes of designated facilities when costs, physical limitations, geographical location, or other factors make sub-categorization appropriate."
    - Proposed model rules or a "model approach" to facilitate development of SIPs, but the states need not adopt any particular approach.

- **State SIPs**: States prepare their plans and implement the elements of approved SIPs:

  - In parallel with EPA's development and issuance of proposed and final guidelines, a state may begin to plan its SIP, informed by increasingly more concrete information provided through the process and adopted in the final EPA guidance.
  - A state's SIP, due to be filed at EPA one year after EPA finalizes its guidance, will describe how the state proposes to satisfy the EPA guidance, either through adopting the EPA approach (if one is provided) or through a program that would provide equivalent emissions reductions achieved via elements preferred by the state.
  - A SIP may need to contain, for example:
    - "Emission standards and compliance schedules 'no less stringent than emission guidelines',"[27] with the regulations (under Section 110) allowing for equivalency where the resulting emission limit is quantifiable, accountable, and enforceable, and (based upon replicable procedures) is equivalent to the SIP limit.[28]
    - Methods and procedures for determining compliance.[29]
    - Enforceable increments of progress for compliance schedules longer than 12 months.[30]

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[26] Megan Ceronsky and Tomas Carbonell, "Section 111(d) of the Clean Air Act: The Legal Foundation for Strong, Flexible & Cost-Effective Carbon Pollution Standards for Existing Power Plants," Environmental Defense Fund, October 2013.

[27] OAQPS GHG Presentation.

[28] 57 Fed. Reg. 13567-68.

[29] OAQPS GHG Presentation.

[30] OAQPS GHG Presentation.

- A SIP may propose to "adopt less stringent emission standards or longer compliance schedules than those set out in the guidelines where the State demonstrates"":[31]
    - "Unreasonable cost of control due to age, location or basic process design"
    - "Physical impossibility of installing necessary control equipment"
    - "Other factors specific to the facility or class of facility that make application of a less stringent standard or final compliance time significantly more reasonable."
- A SIP may adopt more stringent standards or shorter compliance schedules than those contained in the guidelines.
- States will need to adopt laws, rules and/or other administrative mechanisms as part of their demonstration that their SIPs will be effective and enforceable.
- If a state does not file a satisfactory SIP or fails to enforce an approved SIP, then EPA has the authority to issue and enforce a Federal Implementation Plan ("FIP").

The likely character of EPA's guidance under CAA Section 111(d)

Until the EPA publishes its proposed Section 111(d) guidance in June 2014 and finalizes it by the following year, observers cannot be sure what that final guidance will contain. There are clues, however, in statements from EPA, as well as analyses prepared by many observers. These clues provide a reasonable basis for states and the affected industry to begin their planning (as many states have already done).

In its September 2013 document posing "questions to the states," for example, EPA identified two "different options available for addressing carbon pollution from existing power plants… A source-based approach evaluates emission reduction measures that could be taken directly at the affected sources—in this case, the power plants. A system-based approach evaluates a broader portfolio of measures including those that could be taken beyond the affected sources but still reduce emissions at the source."[32]

EPA has typically adopted a source-based approach in other Section 111 regulations.[33] In developing its proposed GHG emission standards for *new* fossil power plants under Section 111(b), for example, EPA relied upon a source-based approach, expressed as a limit on pounds

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[31] OAQPS GHG Presentation.

[32] EPA Design Considerations 2013.

[33] EPA, "Background on Establishing New Source Performance Standards (NSPS) Under the Clean Air Act," October 2013, http://www.epa.gov/region9/air/listening/BackgroundEstablishingNewSourcePerformanceStds.pdf;

of CO_2 emitted for each MWh of generation. The proposal has one CO_2/MWh rate for new Electric Utility Steam Generating Units ("EGUs") that propose to use a solid fossil fuel (e.g., coal-fired boilers) and integrated gasification combined cycle ("IGCC") units,[34] and another rate for natural-gas-fired combustion units.[35],[36]

Many parties outside of EPA have made recommendations and proposals for the form of regulations they prefer to see EPA adopt in its guidance. In terms of the design and stringency of the requirement, these proposals differ in two dimensions (as described recently by Bruce Phillips/Clean Air Task Force[37]): "(1) Whether the rule establishes separate emission standards for covered coal and natural gas-fired generation or a blended emission standard for all covered fossil generation (both coal and natural gas). (2) Whether the emission standards are expressed as an emission rate (in pounds of carbon emissions per unit of generating output) or a mass-based standard (in tons of carbon emissions). As shown in the following table, these two basic design elements characterize the policy proposals and concepts offered to date."

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[34] EPA has proposed standards of performance for utility boilers and IGCC units based on partial implementation of carbon capture and storage ("CCS") as the BSER. "There are two limits for fossil fuel-fired utility boilers and IGCC units, depending on the compliance period that best suits the unit. These limits require capture of only a portion of the CO2 from the new unit. These proposed limits are: (a) 1,100 lb CO2/MWh gross over a 12-operating month period, or (b) 1,000-1,050 lb CO2/MWh gross over an 84-operating month (7-year) period. All standards are in pounds of CO2 per megawatt-hour (lb CO2/MWh gross)." EPA Fact Sheet, "Reducing Carbon Pollution From Power Plants Moving Forward On the Climate Action Plan," September 20, 2013; EPA 2013 Proposed GHG Standards for New EGUs, pages 15-16.

[35] "EPA is proposing two standards for natural gas-fired stationary combustion units, depending on size. The proposed limits are based on the performance of modern natural gas combined cycle (NGCC) units. These proposed limits are: (a) 1,000 lb CO2/MWh gross for larger units (> 850 mmBtu/hr); and (b) 1,100 lb CO2/MWh gross for smaller units (≤ 850 mmBtu/hr)." All standards are in pounds of CO2 per megawatt-hour (lb CO2/MWh gross." EPA Fact Sheet, "Reducing Carbon Pollution From Power Plants Moving Forward On the Climate Action Plan," September 20, 2013; EPA 2013 Proposed GHG Standards for New EGUs, page 16.

[36] I do not mean to suggest that the *particular* form or level of the CO_2/MWh standards proposed in the Section 111(b) rulemaking for *new* power plants will be the same form or level of standards applicable to *existing* power plants. Indeed, EPA has stated that the particular CO_2/MWh standards proposed in the rulemaking for new power plants will *not* be the same standards applicable to existing power plants: "In September [2013], the EPA announced its new proposal. The proposed standards would establish the first uniform national limits on carbon pollution from future power plants. They will not apply to existing power plants." Opening Statement of Janet McCabe, Acting Assistant Administrator, Office of Air and Radiation, EPA, Hearing on EPA's Proposed GHG Standards for New Power Plants and H.R. __, Whitfield-Manchin Legislation, Subcommittee on Energy and Power, Committee on Energy and Commerce, U.S. House of Representatives, November 14, 2013.

[37] Bruce Phillips, The Northbridge Group, "Alternative Approaches for Regulating Greenhouse Gas Emissions from Existing Power Plants under the Clean Air Act: Practical Pathways to Meaningful Reductions," prepared at the Request of the Clean Air Task Force, February 27, 2014 (hereafter, "Phillips/CATF 2014").

Table 1 TAXONOMY OF ALTERNATIVE POLICY DESIGNS[38]		
	Blended Fossil Standard	**Separate Coal and Gas Standards**
Rate-Based	**Blended Fossil Emission Rate** [one rate for all fossil sources] • NRDC [*Natural Resources Defense Council*] (trading with uncovered sources)[39]	**Coal Emission Rate & Gas Emission Rate** • CATF [*Clean Air Task Force*] 1.0 • NCC [*National Climate Coalition*] (trading with uncovered sources)[40]
Mass-Based	**Fossil Budget** (ceiling on total amount of emissions from covered fossil fuel units) • RGGI [*Regional Greenhouse Gas Initiative*] • California AB 32 [*Cap-and-Trade Program*] • CATF 2.0 Fossil Alternative	**Coal Budget & Gas Emission Rate** • CATF 2.0 Coal Budget/Gas Rate Alternative (with an emission rate standard for natural gas)

EPA reports[41] that commenters have suggested that Section 111(d) guidelines be drafted to accommodate multiple emission-reduction options for state SIPs,[42] including:

- Averaging of emissions from covered units, through tradable credits. "Units would be given emission rate targets. If they emit below the targets, they would generate credits

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[38] I have reproduced the overall structure of the original table in Phillips/CATF 2014 (page 8), but have annotated it [in bracketed italics text] to provide full names for the acronyms in the original table, and with other information as provided in the explanatory text of Phillips/CATF 2014 regarding the table. Note the perspective of Phillips/CATF 2014 (page 8) that "Although the coal budget/gas rate approach is less familiar than the fossil budget approach, there are several advantages. It provides similar compliance flexibility and cost effectiveness to the fossil approach, and during the initial years of a 111(d) power plant policy results in lower emission credit prices, wholesale market prices and potentially lower retail rate impacts. Also, it is fundamentally quite similar to the sulfur dioxide (SO2) trading program established by the CAA Amendments of 1990 and successfully operated since then. Coal plants produce virtually all of the electric sector's SO2 emissions, while natural gas emits only trace amounts. Consequently, the SO2 trading program is effectively a type of mass-based coal regulation. Given these characteristics and advantages, the mass-based coal approach deserves close consideration."

[39] Footnote in the original: Dan Lashof et al., NRDC, "Closing The Power Plant Loophole: Smart Ways The Clean Air Act Can Clean Up America's Climate Polluters, December 2012.

[40] Footnotes in the original: "The NCC policy concept calls for renewable and demand side efficiency crediting to play a critical role in the rule." National Climate Coalition, "Using EPA Clean Air Act Authority to Build a Federal Framework for State Greenhouse Gas Reduction Programs." September 2013. Phillips/CATF 2014, page 7-8.

[41] EPA Design Considerations 2013.

[42] EPA has also indicated that although it has historically issued a model rule, the agency is "exploring whether and how to develop a 'toolbox' of decision-making and implementation resources for states that might include information about state programs and measures that reduce electricity sector CO2 emissions. Examples of information in the decision-making toolbox might include criteria for demonstrating how system-wide actions can meet the level of performance in the emission guidelines; a compendium of existing state energy and GHG policies, programs, and measures that includes information about key design attributes and how the states are estimating energy savings and emission reductions; and links to tools that help quantify energy savings and emissions reductions from state programs and measures." EPA Design Considerations 2013.

for each MWh generated. If they emit above the targets, they would still be able to comply if they obtained credits to offset emissions above the target."

- "Generation performance standards," which EPA depicts as similar to emissions averaging "but would include all generating sources (e.g., renewables, nuclear, etc.)."
- "Intrastate emission trading programs with GHG limitations."
- "Other programs that impact a State's generation mix and could lead to reductions in emissions from covered sources such as renewable portfolio standards, clean energy standards," or "increases in end-use efficiency and demand-side management."

These clues provide a reasonable basis to expect that the final rule will give states many options to meet CO_2 reductions cost-effectively and reliably and in ways tailored to the generation mix and policy preferences of the particular state.

Section 111(d) Differs from Other Recent EPA Regulations Affecting Power Plants

The character of Section 111(d)'s regulatory framework creates an entirely different and potentially much-wider set of compliance and implementation options compared to other federal regulations that have affected the electric industry in recent memory. The 'cooperative federalism' model embedded in Section 111(d) provides for much more compliance flexibility and creativity than was possible for the many unit-specific regulations issued recently by EPA. This is core to the conclusion that EPA's regulation of GHG emissions from existing power plants will not raise electric system reliability concerns.

The MATS Rule

For example, one of the most recent EPA regulations affecting existing fossil-fuel power plants – the MATS rule – differs in fundamental ways from Section 111(d). In the MATS rule, EPA set uniform, national standards to reduce emissions of mercury and other toxic air pollutants from approximately 1,100 coal-fired EGUs and 300 oil-fired EGUs located in the U.S.[43], [44] The regulations set limits on allowable emissions that could occur at each affected unit by the compliance dates.

[43] The 12-16-2011 MATS rule also adopted standards for new power plants, which were updated in March 2013.

[44] EPA, "Reducing Toxic Pollution from Power Plants: Final Mercury and Air Toxics Standards (MATS)," December 2011 presentation, page 11.

EGUs generally have up to four years (and in a limited number of instances, a fifth year) to comply with MATS,[45] through a range of compliance strategies to be undertaken at the specific generating units covered by the regulation. "Many existing sources will comply with the MATS by controlling their emissions, while others (typically older, smaller, less efficient units) may choose to cease operations rather than install control technologies."[46] No trading or averaging is allowed across different generating stations. There is no possibility of purchasing compliance credits from over-compliance at other generating stations.

A vibrant public debate took place during the 2010-2012 period about the ability of the electric industry to maintain electric system reliability while also complying with MATS, because those EGUs not yet in compliance would either have to invest in pollution-control technology to comply with MATS, or shut down.[47],[48] Reliability concerns focused on the fact that such a large portion of the nation's generating fleet would be affected, and on whether the systems in which they were located could respond appropriately (and reliably) given those regions' heavy reliance on coal-fired generation. Other concerns focused on whether pollution-control equipment manufacturers and installers could absorb the simultaneous demand for work orders from the owners of so many affected units, and whether the rule would force coal units to retire and create shortages of generation capacity in some regions.

To address such concerns, the EPA took the unusual step in December 2011 (when it finalized its MATS regulation) of issuing a specific statement of enforcement policy to explain that, "where there is a conflict between timely compliance with a particular requirement and electric reliability, the EPA intends to carefully exercise its authorities to ensure compliance with

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[45] MATS includes a 3-year compliance period, with an extension of the compliance deadline for a 4th year for units able to demonstrate to state permitting authorities that additional year is needed for installing technology. In some cases a 5th year may be allowed, in light of EPA intention to allow use of administrative orders "with respect to sources that must operate in noncompliance with the MATS for up to a year to address a specific and documented [electric] reliability concern." EPA December 2011 MATS Enforcement Policy Letter. This would extend MATS compliance deadlines from April 2015 to April 2016 for certain units.

[46] EPA December 2011 MATS Enforcement Policy Letter.

[47] Note that many generating units covered by the MATS rule were already compliant with the emissions limits as of the issuance of the MATS rule. See M. Bradley, S. Tierney, C. Van Atten, and A. Saha, "Ensuring a Clean, Modern Electric Generating Fleet while Maintaining Electric System Reliability," Fall 2011 Update, November 2011.

[48] During the two-year period of 2010 and 2011, countless industry reports and analyses, conference presentations, financial analyst calls, media articles, congressional hearings, and other public reviews focused on the question of whether the EPA's adoption of the mercury and air toxics rules, either alone or in conjunction with other potential EPA regulations affecting existing power plants (including CSAPR, the coal-ash rule, and the cooling water intake structure rule (Section 316(b) of the Clean Water Act)) that were being considered at the time, would introduce local or regional electric system reliability issues. Note one of my own analyses on this topic from early 2011: S. Tierney, "Electric Reliability under New EPA Power Plant Regulations: A Field Guide," January 18, 2011. http://www.wri.org/stories/2011/01/electric-reliability-under-new-epa-power-plant-regulations-field-guide.

environmental standards while addressing genuine risks to reliability in a manner that protect public health and welfare."[49]

At present, the industry is proceeding with its planning in light of the final MATS regulation. (See further discussion, below, on how MATS compliance affects the conditions under which the states and the industry will develop their responses to EPA guidance under Section 111(d).)

How Section 111(d)'s Framework Differs from the MATS Rule

There several reasons why the types of reliability concerns raised during the discussions of the MATS rule in 2010-2011 are not relevant to the Section 111(d) regulations. First, Section 111(d)'s reliance on the SIP process means that EPA will be able to provide states with guidance allowing considerable and wide-ranging latitude in how they plan to meet EPA's requirements. EPA's guidance will not likely impose a common emission standard that must be met solely by actions taken at each affected unit. Rather, EPA is likely to establish standards specific to each state, based on the "degree of emission limitation achievable through the application of the best system of emission reduction," which may vary across states given their own particular circumstances. Each state will have flexibility to propose its preferred actions that accomplish the targeted reductions, as long as the SIP provides reductions across the facilities in the state that are at least as effective as EPA's approach. As EPA Acting Administrator for Air and Radiation told state regulators recently, "We get it that states are in very different positions and that they're thinking about these issues in their own context."[50]

Second, if a state has concerns about the reliability implications of potential temporary or permanent outages of units needed to respond to EPA guidance, the state can take that fact

[49] EPA December 2011 MATS Enforcement Policy Letter, pages 1, 4: "The EPA generally does not speak publicly to the intended scope of its enforcement efforts, particularly years in advance of the date when a violation may occur. The Agency is doing so now with respect to the MATS to provide confidence with respect to electric reliability. EGUs may be needed to operate to maintain the reliability of the electric grid when they would prefer, or could be required, to halt operations temporarily (until controls can be installed) or indefinitely (through deactivation of a unit). …Some sources may take all steps necessary to comply with the MATS, but may nevertheless be needed to operate in noncompliance with the MATS to address concerns with electric reliability. In the event that such sources are interested in receiving a schedule to come into compliance while operating, the EPA intends, where necessary to avoid a serious risk to electric reliability, and provided the criteria set forth herein are met, to issue an expeditious case-specific AO [Administrative Order] to bring a source into compliance within one year….Any such AOs would be issued on or after (not before) the MATS Compliance Date and would be limit to units that are required to run for reliability purposes that (A) would otherwise be deactivated, or (B) due to factors beyond the control of the owner/operator, have a delay in installation of controls or need to operate because another units has had such a delay."

[50] Remarks of Janet McCabe, Acting Administrator for Air and Radiation, presented to the National Association of Regulatory Utility Commissioners, February 11, 2014.

explicitly into account as it designs its SIP. For example, a state may propose plan elements that enable early action/compliance at some Section 111(d) generating units in exchange for allowing more time for others, or that allow emission averaging or emission-credit trading that achieve deeper reductions at one unit in exchange for lighter reductions at another. (The many options available to states in developing their SIPs are discussed below, in the section on "Planning for compliance with EPA guidance.")

Third, the Presidential Memorandum directing EPA to use its Section 111(d) authority explicitly calls for the agency to "develop approaches that allow the use of market-based instruments, performance standards, and other regulatory flexibilities" that are not possible under the statutory language governing MATS. The Presidential Memorandum further directs EPA to develop its standards, regulations or guidelines to:

> identify and use the best, most innovative, and least burdensome tools for achieving regulatory ends…[and to] propose or adopt a regulation only upon a reasoned determination that its benefits justify its costs (recognizing that some benefits and costs are difficult to quantify); (2) tailor its regulations to impose the least burden on society, consistent with obtaining regulatory objectives, taking into account, among other things, and to the extent practicable, the costs of cumulative regulations; (3) select, in choosing among alternative regulatory approaches, those approaches that maximize net benefits (including potential economic, environmental, public health and safety, and other advantages; distributive impacts; and equity); (4) to the extent feasible, specify performance objectives, rather than specifying the behavior or manner of compliance that regulated entities must adopt; and (5) identify and assess available alternatives to direct regulation, including providing economic incentives to encourage the desired behavior, such as user fees or marketable permits, or providing information upon which choices can be made by the public.[51]

Thus, the inherent authority within 111(d), combined with these Presidential directives, invites (if not requires) EPA to implement a flexible framework that will allow states to propose SIPs that take into account the need to assure electric system reliability. As such, the reliability red flag is mainly useful as a spur toward advanced planning, and to motivate states to prepare SIPs with elements addressing (and mitigating) such concerns. (See further discussion below.)

[51] This language is from Executive Order 13563, reflecting the Presidential Memorandum direction that EPA develop its guidance in a manner "consistent with Executive Orders 12866 of September 30, 1993, as amended, and 13563 of January 18, 2011." The latter Executive Order is "13563: Improving Regulation and Regulatory Review."

Power plants that are subject to CAA Section 111(d)

EPA has previously indicated that its Section 111(d) regulations will apply specifically to existing EGUs:[52] all grid-connected steam generators that use fossil fuel and are over 25 megawatts ("MW") in size. It is sensible to presume, too, that Section 111(d) will also apply to natural-gas-fired combined-cycle ("NGCCs") generating units, in light of the fact that the Section 111(b) proposal (affecting new power plants) applies to such units as well.[53]

Together, these categories represent a large subset of all of the nation's power plants, and cover most but not all existing fossil-fuel generating units. It does not include either non-grid connected or very-small steam generating units, or simple-cycle peaking units. EGUs and NGCCs represent classes of technologies which may be owned by investor-owned utilities, publicly owned utilities, rural electric cooperatives, non-utility generating companies, and others.

Based on current information about power plants from SNL Financial for 2013, I calculate that there are 3,084 EGUs and NGCC units likely to be directly affected by EPA's upcoming regulations.[54] (See Table 2.) These generating units represent approximately 532.4 GW of generating capacity,[55] with 292.4 GW of coal-fired power plants (mainly EGU capacity), 216.6

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[52] "The regulations would apply to each EGU capable of combusting more than 250 million British thermal units per hour (MMBtu/hr) heat input of fossil fuel: *Electric utility steam generating unit* means any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 megawatts electric (MWe) output to any utility power distribution system for sale. *Fossil fuel* means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat." OAQPS GHG Presentation.

[53] This is based on two assumptions: First, CAA Section 111(d) will apply to EGUs as defined by the EPA (see, for example, the OAQPS GHG Presentation from 2011). Second, Section 111(d) will apply to any categories of existing emission sources that, if they were new sources, would be regulated under Section 111(b). Under EPA's 2013 Proposed GHG Standards for New EGUs, Section 111(b) includes not only fossil-fuel steam generating units but also natural-gas combined-cycle units: "Utility announcements about the status of coal projects, IRPs [integrated resources plans], and EIA projections suggest that, by far, the largest sources of new fossil fuel-fired electricity generation are likely to be NGCC units. The EPA believes, therefore, that it is also appropriate to set a standard for stationary combustion turbines used as EGUs. These units are currently covered under subpart KKKK (stationary combustion turbines). The EPA also proposes to maintain the definition of EGUs under the NSPS that differentiates between EGUs (sources used primarily for generating electricity for sale to the grid) and non-EGUs (turbines primarily used to generate steam and/or electricity for on-site use). That definition defines EGUs as units that sell more than one-third of their potential electric output to the grid. Under this definition, most simple cycle "peaking" stationary combustion turbines, which typically sell significantly less than one-third of their potential electric output to the grid, would not be affected by today's proposal." Page 24 of EPA 2013 Proposed GHG Standards for New EGUs.

[54] The actual number of EGUs as of early 2014 is 1,929 units in light of data for grid-connected steam generating units over 25 MW in size and using coal, natural gas or oil for fuel. In early 2014, there were 1,176 generating units associated with combined cycle technologies, most of which burn natural gas. Source of data: SNL Financial.

[55] Net summer capacity.

GW of natural-gas-fired plants (mainly combined cycle units), and 23.7 GW of plants that burn oil (mainly EGUs).[56] This represents approximately half of total generating capacity in the U.S. as of the first quarter of 2014 (with the rest being primarily nuclear, hydro and wind), and 70 percent of U.S. fossil generating capacity. (See Appendix 2.)

Table 2
Existing Power Generation Capacity in the U.S. as of 3-2014:
All Power Plants and Power Plants Likely to be Subject to Clean Air Act 111(d)

	Generating Units Likely to Be Directly Covered by Section 111(d)* (# Units)	(GW of Capacity)	Total Grid-Connected Generating Capacity in the U.S. (GW)	111(d) Capacity as a Share of Total Capacity (%)
Coal	1204	292.4	303.7	96%
Natural Gas	1,636	216.6	414.3	52%
Oil	244	23.7	38.2	61%
Nuclear	0	0	98.0	0
Hydro	0	0	99.0	0
Wind and Solar	0	0	68.9	0
Other**	0	0	21.7	0
Total	3,804	532.4	1042.4	51%

Source of data: SNL Financial, March 2014. "GW" reflects net summer capacity of the generating units.
* This reflects existing grid-connected EGUs over 25 MW and NGCCs.
** This includes biomass, geothermal, and generation from other fuels not listed above.

Figure 1 shows the location of all U.S. fossil power plants by fuel type. Given the different fuel/technology mixes of power plants across the states, Section 111(d) will impact the states in different ways:

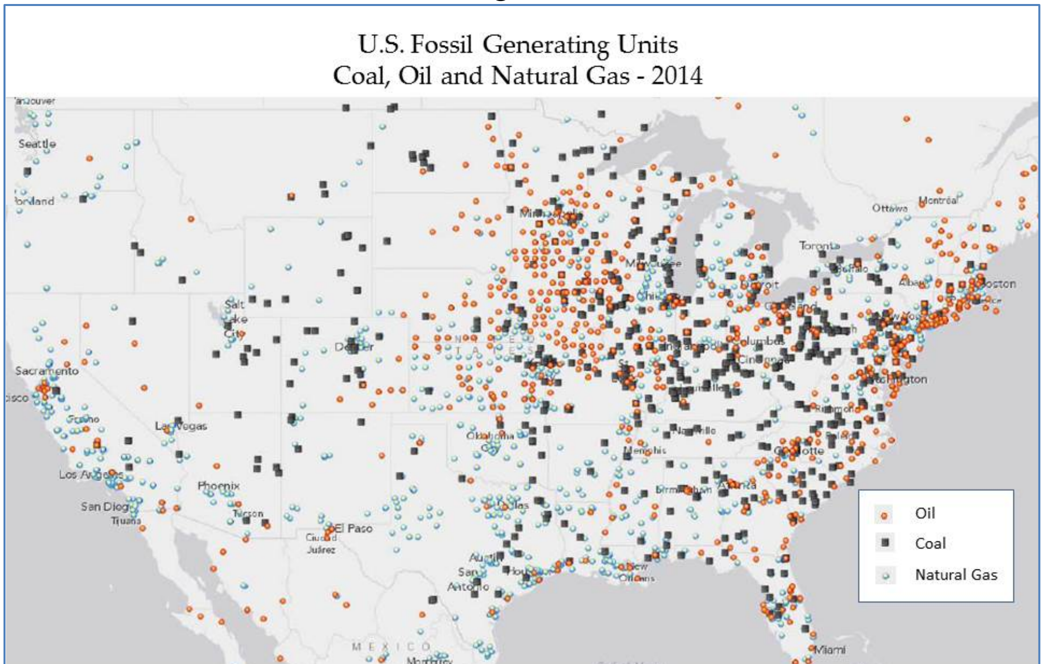
- States with half of their in-state generating capacity likely to be subject to Section 111(d) are (ranked by percentage of total capacity in the state): West Virginia (highest at 88 percent), Utah, Wyoming, Kentucky, Indiana, Louisiana, Delaware, Ohio, New Mexico, Oklahoma, Texas, Missouri, North Dakota, Missouri, Arkansas, Rhode Island, Massachusetts, Maryland, Wisconsin, Florida, Nebraska, Michigan, Alabama, Pennsylvania, and Hawaii (with 50 percent).

[56] These estimates are based on the primary fuel of plants, some of which may burn a second fuel.

- States with a relatively high share of the nation's total generating capacity affected by Section 111(d) are as follows (ranked by highest percentage of total capacity in the U.S.): Texas (12 percent), Florida, California, Pennsylvania, Ohio, Indiana, Georgia, Illinois, Louisiana, Alabama, New York, Michigan, Kentucky, Oklahoma, West Virginia, North Carolina, and Missouri (3 percent).

Appendix 2 provides state-specific information about power plant capacity and units likely to be directly subject to 111(d), along with other capacity in the each state's electric generating fleet. Forty-nine of the 50 states will need to prepare a SIP to show how the state plans to bring its generating facilities into compliance with EPA guidance.

Figure 1



Data source: ESRI

Roughly one quarter of that Section 111(d) capacity (and 28 percent of the units) entered service prior to 1970, and is thus at least 43 years old. Approximately 352 EGUs (with a total capacity of 43.2 GW) are older than 53 years. Owners of 119 of the old (pre-1970) EGUs (with a capacity totaling 16.7 GW) have announced that they intend to retire the unit in a year prior to the end of

2016.[57] These tend to be much smaller units, two-thirds of which are coal-fired EGUs and one-fourth oil-fired EGUs.

Approximately three percent of the directly affected EGU and combined-cycle capacity (18.8 GW) operating at the start of 2014 has a planned retirement occurring between 2013 and 2016 – well before the compliance period for SIP implementation[58] (and roughly consistent with the date by which existing coal-fired and oil-fired EGUs will have had to comply with the EPA's MATS rule[59] or retire). Using this information as a proxy for upcoming retirements, approximately 523 GW of capacity nationwide would be subject to Section 111(d) after 2016. (See further discussion below regarding power plant retirements.)

Context for Industry Compliance with CAA Section 111(d) Requirements

Several trends affecting the electric industry set the stage for the roll-out of new regulations. Foremost among these trends are: the 'shale gas' revolution and its implications for coal plant economics (including the availability of higher levels of output from existing natural-gas power plants); relatively flat demand for electricity; growth in development of renewable energy; the availability of supply from zero-carbon nuclear generation; the announcements of retirements of coal-fired generating capacity that result from these factors and the EPA's MATS rule; and proposals to build new power plants. These trends set the context for EPA and the states preparing to address GHG emission reductions. And they affect the factors that states will need to consider as they plan for electric-system reliability as part of that process.

Natural gas, coal and existing power plants

Until the past few years, energy market fundamentals favored use of coal for power generation in many parts of the U.S. The recent shale gas revolution has fundamentally changed that

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[57] Analysis based on SNL Financial data.

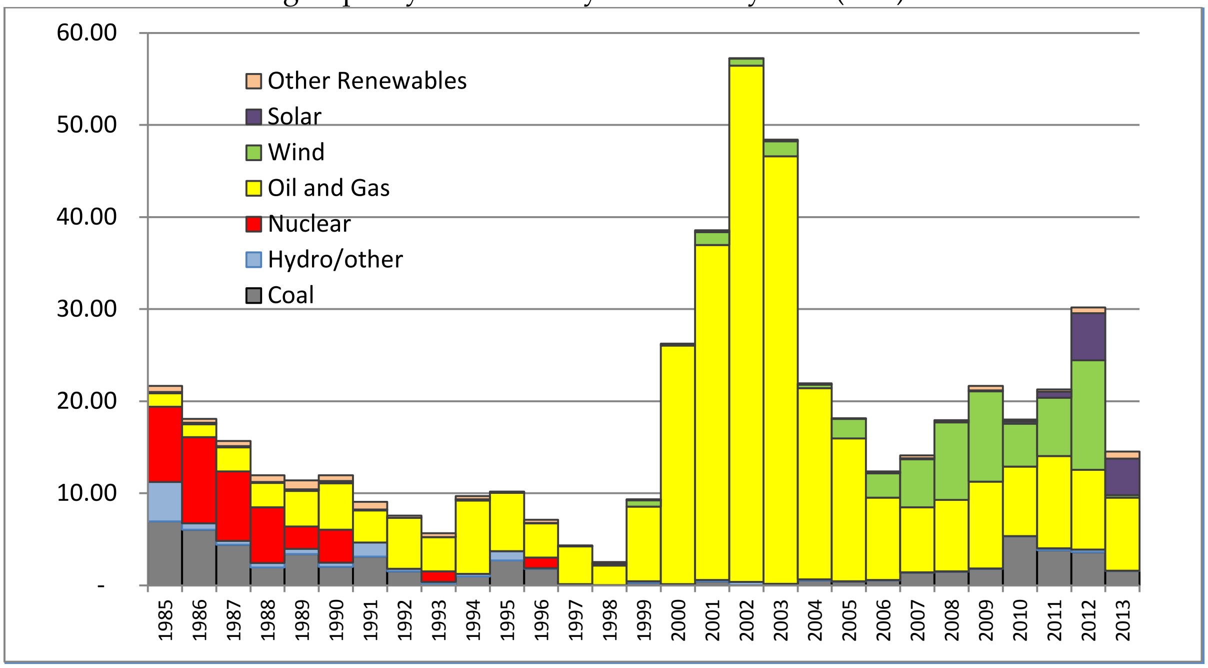
[58] The Presidential Memorandum requests that EPA's 111(d) guidelines require states to submit their SIPs by no later than June 2016. Assuming this optimistic time frame and taking into account time for EPA review and state implementation, compliance would actually likely begin no earlier than late 2017. (See, for example, the schedule showing an estimated compliance period for Section 111(d) spanning roughly late 2017 through 2020, as presented by Jennifer Macedonia, Bipartisan Policy Center, "Clean Air Act Regulation of Power Plants: Greenhouse Gas Performance Standards," September 2013, page 4.)

[59] See December 16, 2011, letter of Cynthia Giles, Assistant Administrator of the Office of Enforcement and Compliance Assurance, EPA, re: the EPA'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" (hereafter, "EPA December 2011 MATS Enforcement Policy Letter").

situation. Low natural gas prices over the past few years[60] have put economic pressure on coal facilities. Natural-gas-fired power plants increased their output (from 22 percent of U.S. power production in 2007, to 28 percent in 2013), while coal-fired generation decreased (from 49 percent in 2007 to 39 percent 2013).[61] Fuel-switching and re-dispatch of existing power plants was possible in light of the significant amount of gas-fired generating capacity that had been added in the U.S. since 2000 (Figure 2) and that had been underutilized for many years.

Figure 2

Generating Capacity Additions by Year and by Fuel (GW): 1985-2013



Source: EIA, Annual Energy Outlook 2013, Figure 78.

Low gas prices resulted from a combination of lower demand for energy (from the U.S. economic downturn and other factors[62]), and generally lower production costs associated with unconventional gas production. (See Figure 3 for wellhead prices of natural gas and in Figure 4 for prices of natural gas futures.) Market pressure resulting from low natural gas prices led to

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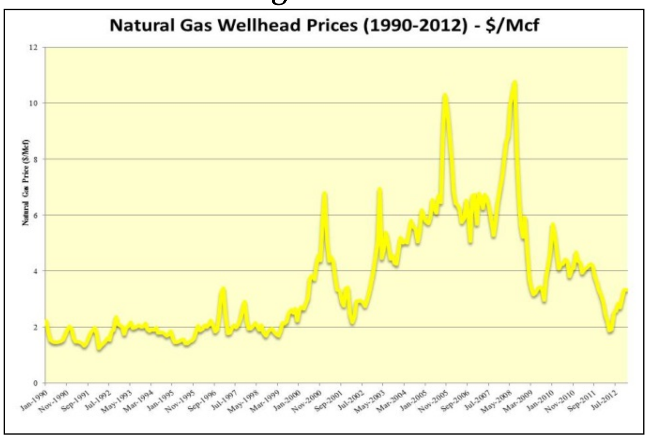
[60] Note that natural gas commodity prices spiked in many parts of the U.S. where extremely cold weather occurred in December 2013 and mid-January 2014. See SNL Financial.

[61] Source: EIA, Electric Power Monthly, Table 1.1. Net Generation by Energy Source: Total (All Sectors), 2003-November 2013. Information for 2013 is for the 11 months (January through November).

[62] Including states' promotion of increased funding for energy efficiency programs and stronger appliance efficiency standards.

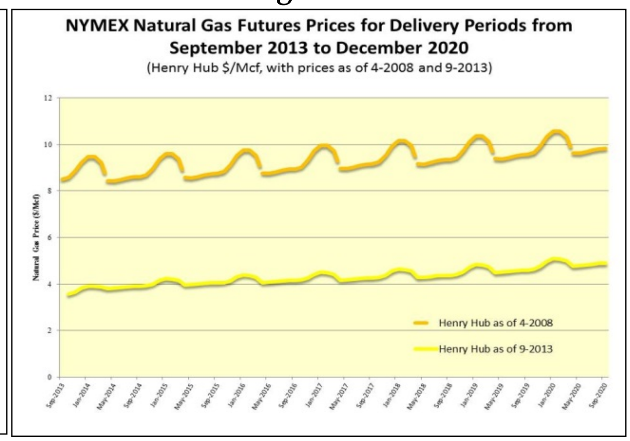
announcements of retirements of some of the oldest, smallest and least-efficient coal plants, as discussed previously.[63] Figure 5 shows the cumulative amount of coal-fired generating capacity (a total of 25.4 GW) that retired without reliability problems in the 2008-2013 period, in various regions of the U.S. It also shows the amount of capacity (an additional 20 GW) that has been announced to retire between 2014 through 2018. Most of the retiring capacity is located in the RFC and SERC regions – areas with substantial coal-fired generation and underutilized natural gas capacity.

Figure 3



Source: EIA

Figure 4



Source: SNL Financial

Given the significant amount of natural-gas-fired generating capacity added since 2000, these plants have not operated at full capacity, even as natural gas prices dropped in recent years and made it more economical to operate gas-fired plants.[64] This underutilized gas-fired capacity represents existing capacity that could operate more and could supply consumers' power requirements in the event of retirements of other power plants, operating restrictions on other high-emitting plants, and/or increased costs to run coal-fired power plants.

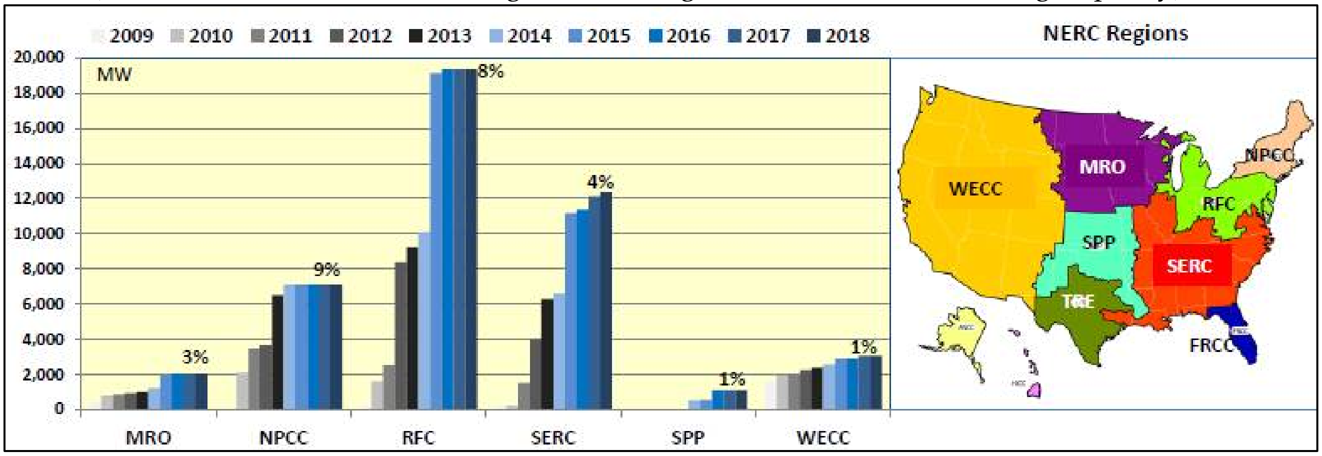
[63] A longer explanation of such market changes is in my February 2012 paper called "Why Coal Plants Retire: Power Market Fundamentals as of 2012."

[64] This is particularly true compared to prior years (e.g., during the period from roughly 2001 through 2008), when gas prices were relatively volatile and high (compared to most of the period since then, as shown in Figure 3).

Figure 5

Generating Capacity Associated Actual Coal-Plant Retirements (2009-2013) and Planned Coal Capacity Retirements (2014-2018) by NERC Region

(With Retirements as a Percentage of Each Region's Total 2012 Generating Capacity)

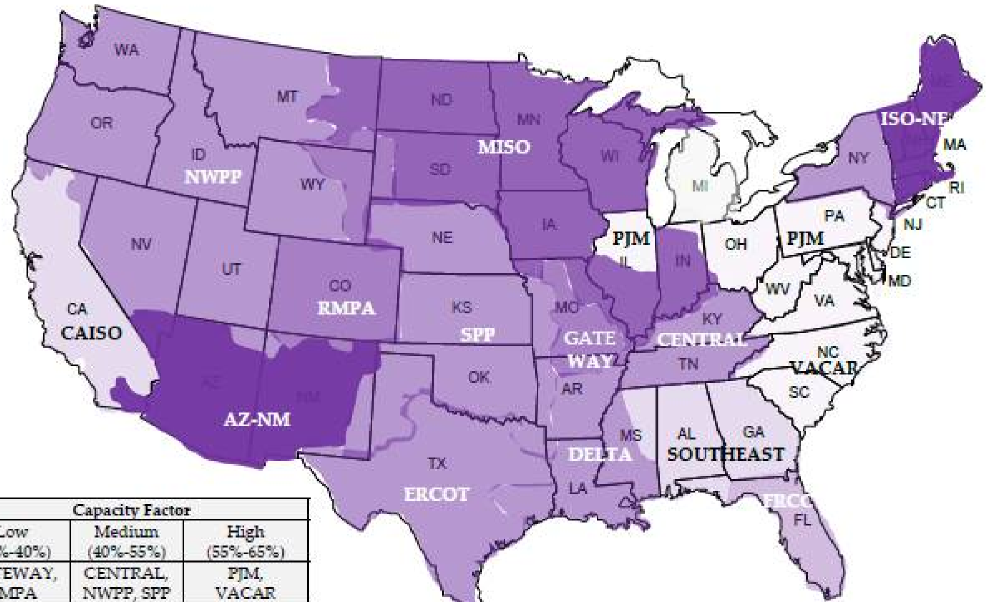


Source of data: SNL Financial, March 25, 2014. "NERC Region" refers to NERC's reliability regions (shown on the map). Note that there are no actual or planned retirements during the 2008-2018 period for TRE and FRCC.

The states and regions vary with respect to their reliance on natural gas capacity (e.g., NGCC capacity as a percentage of total capacity in the region) and their dispatch of NGCCs (i.e., their capacity factors, or the percentage actual output relative to their potential to produce power). Figure 6 shows the various regions, with shading indicating the extent to which there is significant under-utilized NGCC capacity that could be dispatched to meet power requirements in the event of restricted output at or retirement of coal plants. A lighter-shaded color indicates that the region's electric mix has relatively low reliance on NGCC capacity, but operates them relatively frequently. A darker-shaded color indicates that that region has relatively high reliance on NGCC capacity but with low capacity factors at those plants.

Figure 6

Regional Reliance on Natural Gas-Fired Combined Cycle in 2012 as a Percentage of Total Generating Capacity and in terms of Asset Utilization (Capacity Factor):



		Capacity Factor		
		Low (25%-40%)	Medium (40%-55%)	High (55%-65%)
Percent of Total Capacity (Summer)	Low (3%-15%)	GATEWAY, RMPA	CENTRAL, NWPP, SPP	PJM, VACAR
	Medium (15%-33%)	MISO	NYISO	CAISO, SOUTHEAST
	High (33%-41%)	AZNM, ISO-NE	DELTA, ERCOT	FRCC

Source of data: SNL data (on NGCC power plants and capacity factors) by NERC subregion as of 2012. NERC regions and subregions are shown in Appendix 3. Note: There were no regions with less than 3 percent or more than 41 percent reliance on NGCC capacity (as a percentage of total summer capacity in 2012). No regions had an average NGCC capacity factor lower than 25 percent and higher than 65 percent in 2012. In all but one region (NWPP), the average 3-year capacity factor (2011-2013) was lower than the capacity factor in 2012, due to various factors including relative price of natural gas and coal, availability of hydro and/or wind, nuclear outages and/or retirements, coal-plant retirements). The 3-year average was less than 5 percent lower for some regions (i.e., ERCOT, FRCC, ISO-NE, NYISO, RMPA, VACAR), between 5-10 percent lower for others (AZNM, DELTA, and SOUTHEAST), between 10-15 percent lower (CAISO, CENTRAL, PJM, and SPP), and 15-30 percent lower (in GATEWAY and MISO).

This under-utilized NGCC capacity provides an opportunity in most states to incorporate policies and actions in their SIPs that encourage redispatch of existing power plants. For example, the recent Phillips/CATF 2014 analysis indicates that a combination of

> approaches would reduce emissions through a mix of compliance actions: by reducing the heat rates (and consequently the emission rates) of coal units; displacing high emission rate coal generation with lower emission rate gas generation through an emission credit trading program; retiring

> coal generating capacity; and reducing electric demand through customer response to higher electric prices. Of these, the emission reductions from fossil dispatch represent the largest single source of reductions, in both cases approximately 70 percent of total compliance. This is due to the large size and intermediate capacity factors of the existing NGCC fleet (even under current and expected market conditions) and the relatively narrow spread between delivered coal and natural gas prices, especially in the eastern and central regions of the country."[65]

This existing, under-utilized existing capacity provides grid operators with generating resources to dispatch to meet operating requirements reliably. As noted in Figure 6, every region has some existing under-utilized NGCC capacity, and there were no regions with average NGCC capacity factors lower than 25 percent and higher than 65 percent in 2012. As shown in the Appendix 2, a handful of states (Hawaii, Kansas, Kentucky, North Dakota, Vermont, West Virginia, and Wyoming) did not have any NGCC capacity operating in 2012; of these, most of them either have NGCC capacity under construction in their state as of March 2014 (as is the case for Kansas, Kentucky, North Dakota, and Wyoming) and/or are part of a region with significant under-utilized NGCC capacity (as is the case for all of these states besides Hawaii).

Outlook for electricity demand

GHG emissions from fossil fuel power plants are also strongly tied to overall electricity use. Electricity demand has been relatively flat in recent years, with a gradual return to 2007 levels anticipated by next year.[66] Beyond then, EIA estimates that demand will grow approximately 1.5 percent per year through the end of this decade.[67] The current forecast for 2020 is approximately the level of demand anticipated for 2013 before the economic downturn. This provides a degree of breathing room for managing changes in the generation mix.

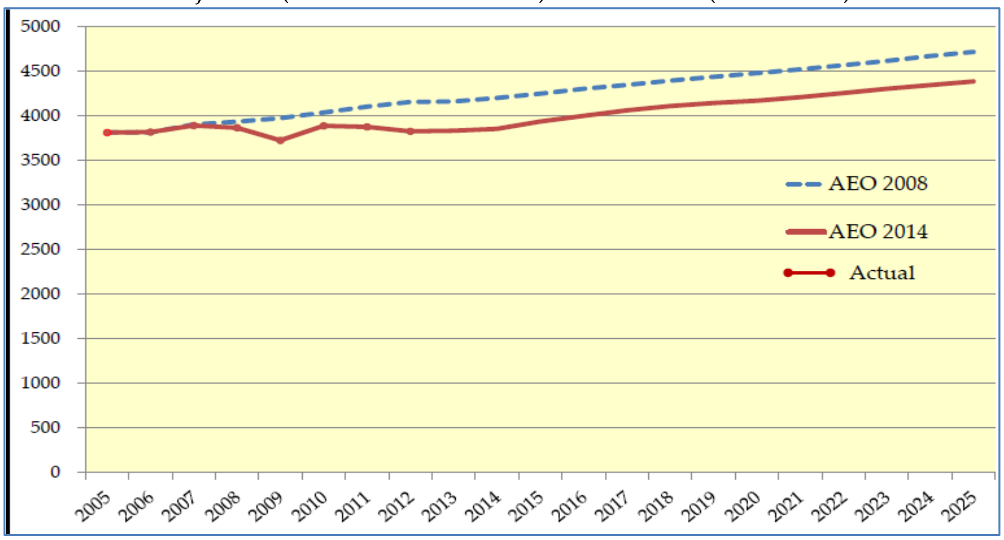
[65] Phillips/CATF 2014, page 21. See also the Appendix in that report.

[66] EIA, Annual Energy Outlook 2014 (Early Release) (hereafter "EIA AEO 2014ER"), and AEO 2008, with actual data from Electric Power Monthly.

[67] The EIA's estimates of demand does not take into account the demand met by on-site renewable generation (e.g., roof-top photovoltaic systems).

Figure 7

Electricity Demand through 2025:
Projected (as of 2008 and 2014) and Actual (2005-2012)



Source of data: EIA, AEO (2008, 2014), and Electric Power Monthly

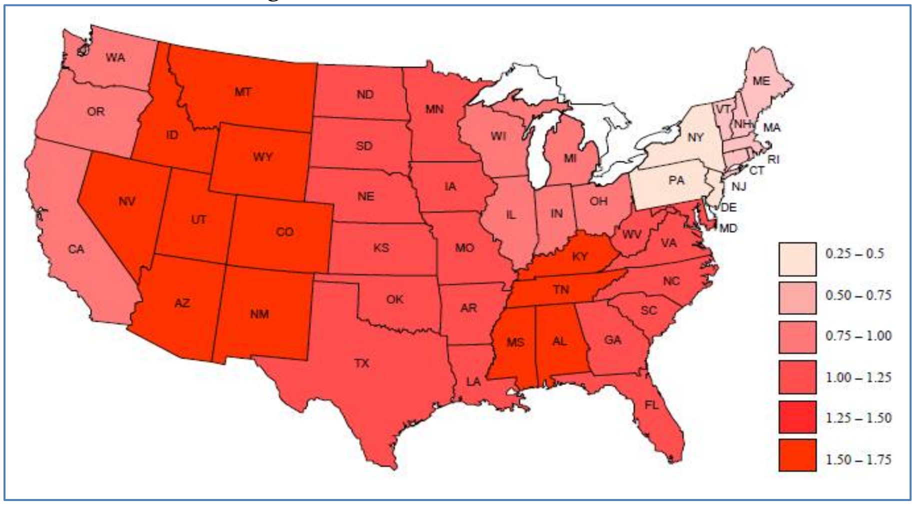
EIA projects different growth rates by region of the country.[68] Regions anticipated to grow faster than the U.S. average are the Mountain states, the Plains states, Texas, and the Southeast.[69] By contrast, EIA projects slower growth for the Pacific states, East North Central states, the Mid-Atlantic, and New England regions.[70] (Figure 8.)

[68] EIA AEO 2014ER, Tables 1-30. http://www.eia.gov/forecasts/aeo/er/tables_ref.cfm, Tables.

[69] West North Central (1.0%/year); South Atlantic (1.1%/year); West South Central (1.2%/year); Mountain (1.7%/year); East South Central (1.7%/year). EIA, AEO 2014ER.

[70] Middle Atlantic states (0.3%/year); New England (0.6%/year); East North Central (0.8%/year); Pacific states (0.8%/year). EIA AEO 2014ER.

Figure 8
Projected Growth in Demand for Electricity by Region:
Average Annual Growth Rate (2012-2020)



Source of data: EIA, AEO 2014ER

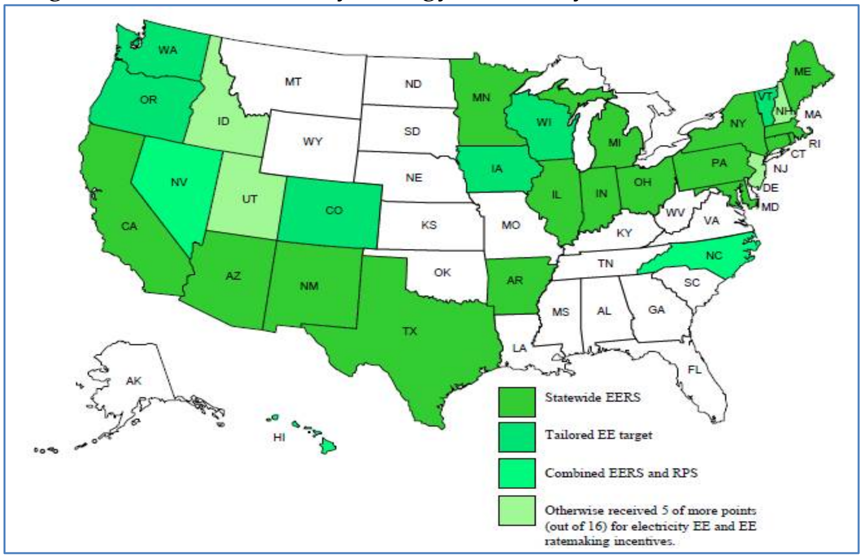
States' growth trends reflect not only different economic activity but also the effect of policy. Many states have adopted energy efficiency policies that enable greater energy productivity through policies such as utility-sponsored energy efficiency programs, building codes, ratemaking incentives for meeting efficiency targets, and an Energy Efficiency Resource Standard ("EERS"). According to the American Council for an Energy Efficiency Economy ("ACEEE"), 26 states "have adopted and adequately funded an EERS, which sets long-term energy savings targets and drives investments in utility-sector energy efficiency programs,"[71] and which "aim explicitly for quantifiable energy savings."[72] Figure 9 shows states with an EERS and other programs promoting efficiency savings in electricity use.

[71] ACEEE, "The 2013 State Energy Efficiency Scorecard," ACEEE Report E13K (hereafter "ACEEE 2013 Efficiency Scorecard"), page vi. The states with a "statewide EERS" as of 2013 are: Arizona, Arkansas, California, Connecticut, Illinois, Indiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, New Mexico, New York, Ohio, Pennsylvania, Rhode Island, and Texas. The states with a version of an EERS that ACEEE calls a "tailored target" are Colorado, Iowa, Oregon, Vermont, Washington, and Wisconsin. And the states that combine a renewables and energy efficiency standard are Hawaii, Nevada and North Carolina. ACEEE 2013 Efficiency Scorecard, page 19.

[72] "Twenty-six states now have fully funded EERS that establish specific energy savings targets through customer energy efficiency programs. These policies set multi-year targets for electricity…, such as 1% or 2% incremental savings per year or 20% cumulative savings by 2025.[fn in the original.] EERS policies aim explicitly for quantifiable energy savings, reinforcing the idea that energy efficiency is a utility system resource on par with supply-side resources. These standards also help utility system planners more clearly anticipate and project the impact of energy efficiency programs on utility system loads and resource needs. Energy savings

Figure 9

States with a Energy Efficiency Resource Standard or With Relatively High Scores for Electricity Energy Efficiency Policies (as of 2013)



Source: Data from the ACEEE 2013 Efficiency Scorecard, Table 8. This table includes all states considered having an EERS (by ACEEE) and otherwise receiving at least 5 of 16 points for electricity energy efficiency ("EE") or EE ratemaking incentives for utilities.

Even states with a strong history of pursuing cost-effective energy efficiency have further opportunities to improve energy productivity in the future.[73] Tapping such opportunities can help states reduce some of the GHG emissions associated with electricity production.[74]

State policies relating to renewable energy

Another factor affecting the outlook for GHG emissions at existing fossil units is the widespread adoption of policies by states to promote use of renewable generation. As shown in Figure 10,

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targets are generally set at levels that push efficiency programs to achieve higher savings than they otherwise would have, typically based on analysis for the energy efficiency savings potential in the state that ensures the targets are realistic and achievable. EERS policies maintain strict requirements for cost-effectiveness so that efficiency programs are guaranteed to provide overall benefits to consumers." ACEEE 2013 Efficiency Scorecard, Page 18.

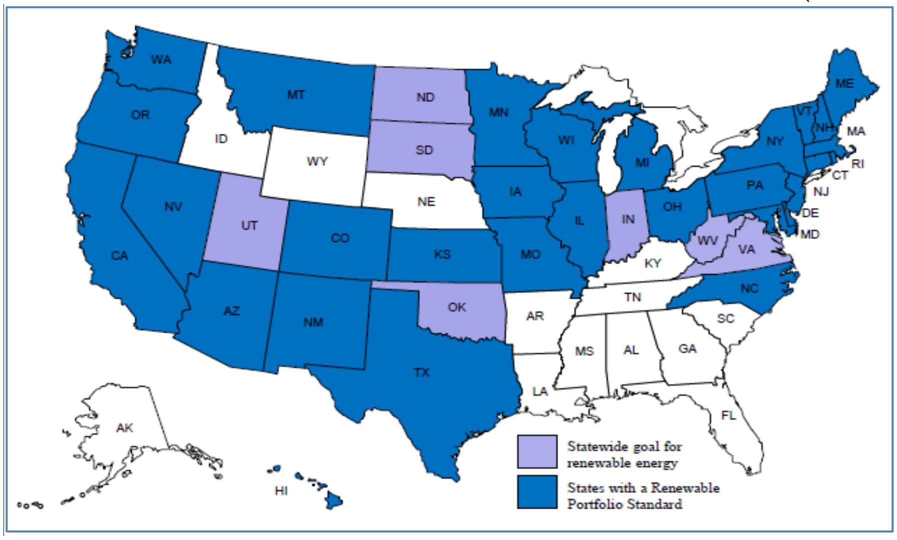
[73] See, for example, the February 7, 2013 report of the Alliance Commission on National Energy Efficiency Policy, "Doubling U.S. Energy Productivity by 2030."

[74] Paul Hibbard and Andrea Okie, "Crediting Greenhouse Gas Emission Reductions from Energy Efficiency Investments: Recommended Framework for Proposed Guidance on Quantifying Energy Savings and Emission Reductions in Section 111(d) State Plans Implementing the Carbon Pollution Standards for Existing Power Plants," March 2014. http://www.edf.org/sites/default/files/eemv-111d-recommended-framework.pdf.

most states have either a Renewable Portfolio Standard ("RPS") that requires that a certain percentage of electricity sold at retail be sourced from renewable energy generation, or a goal for development and use of renewable supplies. Some of these states' RPS policies have been in place for many years, leading to growth in renewable generation in recent years. Figure 11 shows the percentage of states' 2012 generation that came from renewable energy (including wind, solar, geothermal, hydro, wood, wood waste, municipal waste, landfill gas, and other biomass). This output tends to displace output that would otherwise come from fossil generation with GHG emissions.[75]

Figure 10

States with a Renewable Portfolio Standard or Renewables Goals (as of 2013)



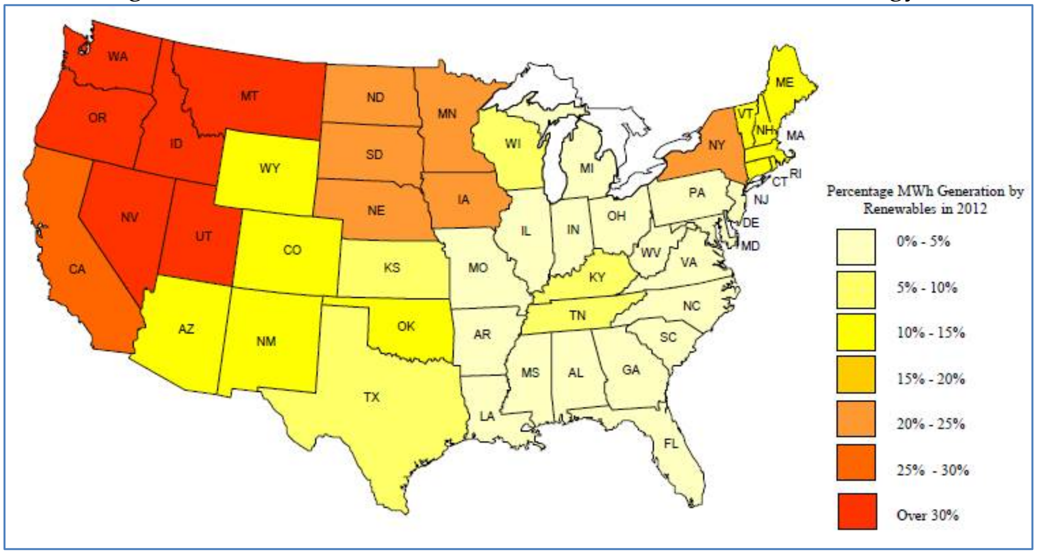
Source: Database of State Incentives for Renewables and Efficiency ("DSIRE")

[75] In the U.S. overall in 2012, renewable generation accounted for 14 percent of total electricity supply. Of this renewable generation, the sources of power production were as follows:

Renewable Generation in the U.S. – Percentage Shares by Fuel/Resource in 2012	
Conventional Hydro	55%
Wind	28%
Wood and Other Biomass	7%
Municipal Wastes	4%
Geothermal	3%
Solar (not including off-grid PV systems)	2%
Total Renewables	100%

EIA, AEO 2014ER, ref2014.d102413a, Table 120.

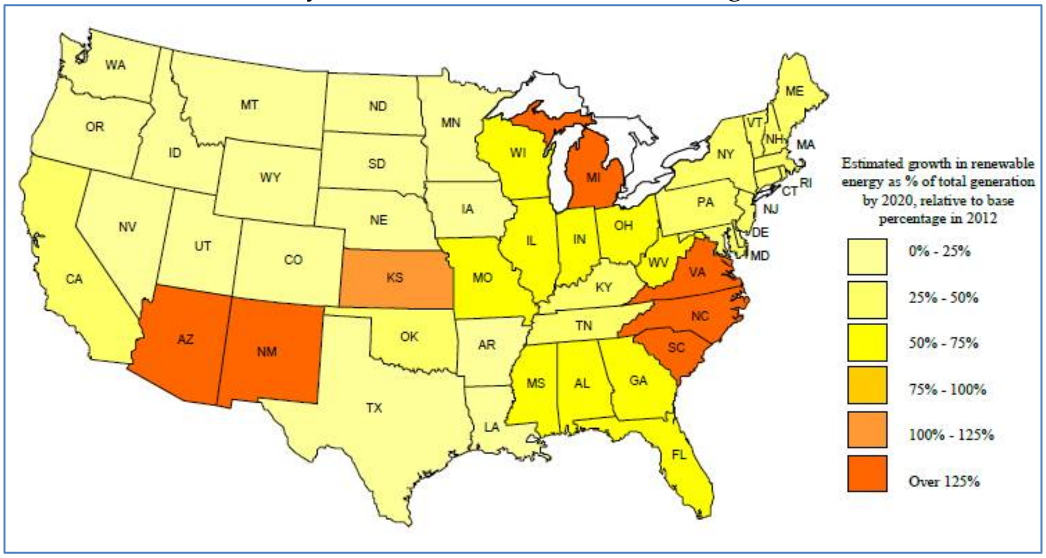
Figure 11
Percentage of States' Total Power Generation from Renewable Energy in 2012



Source of data: EIA, AEO 2014ER, ref2014.d102413a, Table 96. States' output shown on the map above is based on their location within EIA's Electricity Market Module Regions. For states in more than one region, a state has been assigned to the particular region in which the majority of the state is located (by land, not necessarily load). "Renewables" includes wind, solar, geothermal, conventional hydro, wood, wood waste, municipal waste, landfill gas, and other biomass.

EIA projects that in several parts of the country where renewable generation was a relatively small share of total power supply in 2012, there will be substantial growth in renewable output. Figure 12 shows information related to such growth, with the color indicating each state's renewable generation in 2020, as a percentage increase from that state's base of renewables in 2012. The additional renewable supply will come from both utility-scale and distributed renewable energy projects (i.e., facilities located 'behind the meter' on customers' premises). These projections, based on current policy assumptions, provide a reasonable basis for assuming that in the future, renewables will allow for displacement of some of the output from fossil generation in many regions of the country (e.g., the Southeast and Florida, Arizona and New Mexico, Virginia and the Carolinas, Michigan and other parts of the Midwest) in the years ahead. States may be able to plan for such as part of their SIPs, and will likely need to address operational/integration issues that may become more urgent with higher penetration of renewables (although the availability of flexible NGCC will help with this integration).[76]

Figure 12
Projected Growth in States' Renewable Generation
by 2020, Relative to 2012 Percentage



Source of data: EIA, AEO, 2014ER, ref2014.d102413a, Table 96. The information in this chart is based on a comparison of the MWh of generation in 2012 with the projected generation in 2020, with the difference reflecting the percentage change in renewables generation over that period. States with a darker color represent a higher percentage growth in that state. States' output shown on the map above is based on their location within EIA's Electricity Market Module Regions. For states in more than one region, a state has been assigned to the particular region in which the majority of the state is located (by land, not necessarily load). "Renewables" includes wind, solar, geothermal, conventional hydro, wood, wood waste, municipal waste, landfill gas, and other biomass.

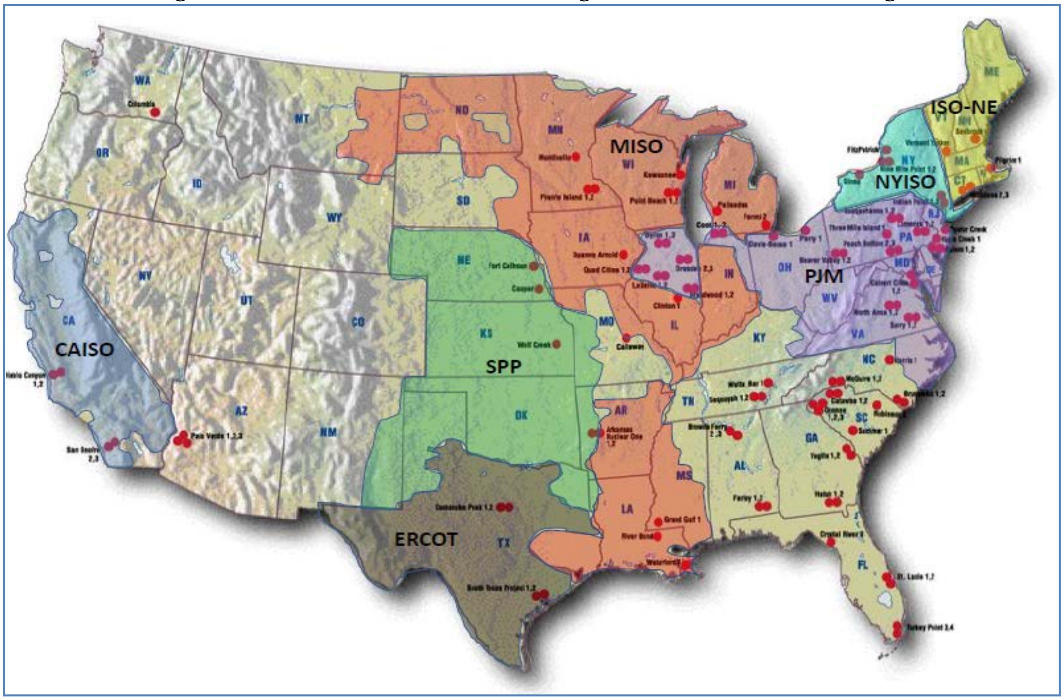
Availability of zero-carbon supply from nuclear generators

For nearly two decades, one fifth of the nation's electricity supply has been generated at nuclear power plants.[77] The currently operating 100 nuclear reactors are located in 31 states, as shown in Figure 13.

[76] See, for example, the recent study performed to examine the operational, cost, emission, and other implications of a 40-percent and 50-percent RPS requirement in California: E3, "investigating a Higher Renewables Portfolio Standard in California, January 2014; and Dan Arvizu, Severin Borenstein, Susan Tierney, and Stephen Wright, "Report of the Independent Advisory Panel Regarding the Five California Utilities' Study of Integration of Renewable Energy into California's Electric System: 'Investigating a Higher Renewables Portfolio Standard in California'," January 2014.

Figure 13

Location of Existing Nuclear Power Plants and Regional Transmission Organizations (RTOs)



Source: World Nuclear Association, http://www.world-nuclear.org/info/Country-Profiles/Countries-T-Z/USA--Nuclear-Power/. Overlay of RTOs (Analysis Group). Note that this map shows the San Onofre (California), Crystal River (Florida), and Kewaunee (Wisconsin) units – all of which were retired as of 2014.

In the past two years, owners of several existing nuclear units have either retired or announced an impending retirement of the plants. The actual retirements include units located in California, Wisconsin, and Florida. A unit retirement will occur in Vermont at the end of 2014. These particular retirements are due to a variety of reasons, including costly repairs and low wholesale power prices.[78]

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[77] EIA, Annual Review of Energy, 2013, Table 7.2b Electricity Net Generation: Electric Power Sector.

[78] San Onofre Units 2 and 3 in California (and totaling 2150 MW) retired in 2013 after being shut down for an extended outage related to a damaged steam generator at the unit, with its owner reporting it would be uneconomic to repair and restart the units, in light of market conditions; Kawanee, a 566-MW unit in Wisconsin shut down in 2013 due to lower power prices in wholesale markets; Crystal River, a 860-MW unit in Florida that was shut down permanently in 2013 down after a decision not to repair the previously damaged station; and Vermont Yankee, a 604-MW unit announced to be retired at the end of 2014 due to unfavorable economics, in spite of a 90+ percent capacity factor. Sources: EIA Generator Y2012 data (860 database on power plants); EIA, "Lower power prices and high repair costs drive nuclear," July 2, 2013; Matthew Bandyck, "UPDATE: Entergy says Vermont Yankee nuke closure shows 'design flaws' in wholesale markets," August 27, 2013.

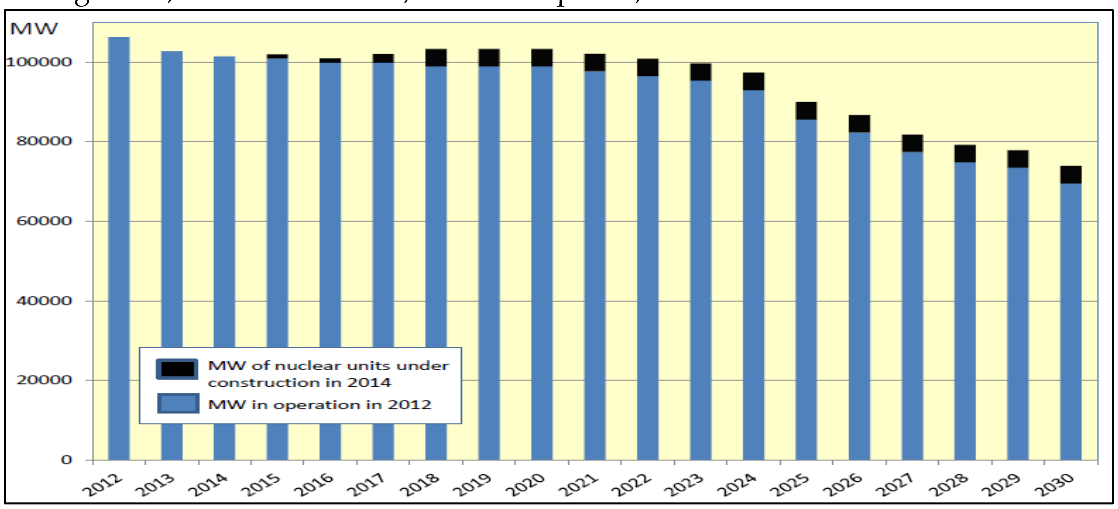
Many of the nation's best-performing nuclear units – including those that operate on a non-utility 'merchant' basis – are under significant economic pressure. Merchant nuclear plants operating in the 'organized' wholesale power markets (shown on Figure 13's shaded regions) have suffered slim profit margins in recent years. This results from many factors, including low natural gas prices, wholesale power-market design flaws, flat electricity demand, rising capital costs, and public policies that favor some low-carbon resources but not others.[79]

Figure 14 shows total nuclear generating capacity, taking into account the effect of recent nuclear retirements, new nuclear units under construction, new capacity uprates, and other nuclear plants retiring at the end of their currently approved operating licenses.

Figure 14

Nuclear Generating Capacity: 2012-2030

(Existing Units, Unit Retirements, Planned Uprates, and Units Under Construction in 2014



Source: EIA, AEO 2014ER.

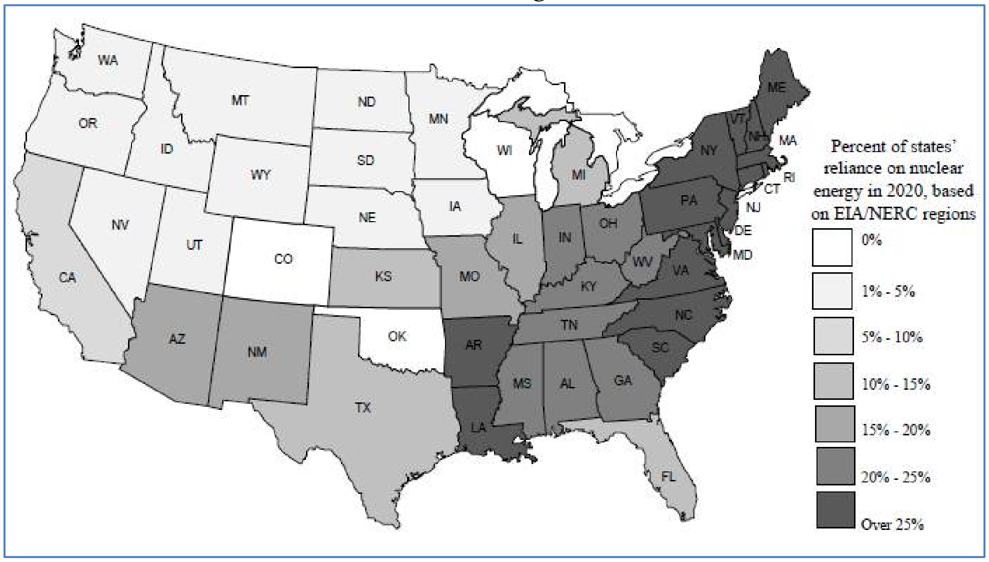
Taking these retirements into account, along with the projected addition of the five nuclear generating units under construction in the Southeast, EIA projects that regions will continue to rely on nuclear plants to produce a considerable share of power supply by the year 2020 (as shown in Figure 15), with declining zero-carbon nuclear generating capacity beyond then (see Figure 14).

[79] See my forthcoming paper: S. Tierney, "Today's Nuclear Fleet: What Role in the Nation's Clean, Affordable and Reliable Power Strategy?"

Figure 15

Projected Regional Reliance on Nuclear Energy 2020

(NERC Subregions[80])



Source of data: EIA, AEO 2014ER, ref2014.d102413a, Table 96. Note that because these projections are based on NERC subregions rather than state-specific generation estimates for 2020, there may be no nuclear units in some states with that show shading (rather than being a white color). Compare Figure 13 to this one, for the location of nuclear units by state. Note that NERC regions and subregions are shown in Appendix 3.

When a nuclear plant retires, its output tends to be replaced (at least in the near term) with generation from plants that burn natural gas, oil or coal. Loss of nuclear units leads, therefore, to higher CO_2 emissions. Reportedly, California's CO_2 emissions increased by 10 percent after the recent loss of the output from the two San Onofre units that shut down in early 2012.[81]

The need to replace zero-carbon generation at any additional nuclear plants that shut down could increase the pressure on states to include Section 111(d) SIP elements addressing this

[80] States' output shown on the map above is based on their location within EIA's Electricity Market Module Regions. For states in more than one region, a state has been assigned to the particular region in which the majority of the state is located (by land, not necessarily load). There may be no nuclear units in some states with a shading (i.e., not white color), in light of the market sub-regions used in EIA modeling.

[81] The California Air Resources Board has reported that CO_2 emissions in the state increased from 2011 to 2012, "primarily due to emission increases from California electricity generation using natural gas as a fuel", which in turn were tied to low hydro conditions, higher demand as a result of warmer weather and a recovery economy, and the shutdown of the San Onofre nuclear station in early 2012. World Nuclear News, "Greenhouse gas emissions from power plants in California increased by 35% in 2012, partly due to the early closure of the San Onofre nuclear power plant," November 5, 2013.

situation. For example, EPA should consider requiring states with existing nuclear plants to demonstrate in their SIPs mechanisms to assure retention of such zero-carbon electricity supply and/or address the potential loss of resources with no GHG emissions. Additionally, the states located in regions with (a) deep reliance on nuclear generation (Figure 15), (b) merchant nuclear plants located in ERCOT, PJM, MISO, NYISO, ISO-NE (Figure 13), and (c) significant coal retirements (Figure 5, and discussion in the following section) should consider including elements in their SIPs to create incentives to retain safely operating zero-carbon generating capacity and/or to recognize the potential to generate electricity with no carbon emissions as a result of any planned nuclear capacity uprates.

Responses to EPA MATS regulations

Owners of many existing coal-fired power plants are planning for their future in light of the EPA's MATS regulations issued at the end of 2011. EGUs affected by the MATS rule will need to be in compliance by 2016, with some exceptions as noted by EPA.[82]

In anticipation of these regulations and in light of market fundamentals, many of the older and less-efficient coal plants may retire before the MATS compliance deadlines. (See Figure 5.) (Various observers have estimated the expected amounts of retirements, but comparisons among them are hard because they reflect different time periods for their baseline generating capacity and forward period for retirements.[83]) Some of the coal plant capacity has already retired (e.g., 25.4 GW from 2008 through 2013, as shown in Table 5), leaving 303.7 GW of coal-fired capacity as of the beginning of 2014. Because owners of plants affected by the MATS rule have until roughly 2016 to comply with the rule's requirements, the retirements occurring before then can be viewed as heavily affected by current power market pressures. In addition to the 25.4 GW already retired, another 18.4 GW has been announced to retired through 2016, with most of that retiring by the end of 2015 and located in the RFC (Midwest) and SERC (Southeast) regions (see Figure 5).

[82] See EPA December 2011 MATS Enforcement Policy Letter.

[83] "Over 52 GW (about 16% of the existing coal fleet) of coal-fired electric generating capacity has been announced for retirement by 2025. Of this, about 45 GW will retire by 2016." Amlan Saha, "Review of Coal Retirements," MJ Bradley Associates, April 2013. SNL has recently reported that owners of 47 GW (roughly 14.6 percent of the 323 GW of coal-fired generating capacity operating as of 2012) have announced the retirement of such units before 2016. Jesse Gilbert and Andrew Gelbaugh, "Coal under fire: Assessing risk factors and market impacts for upcoming coal retirement decisions," SNL Financial, December 2013 (hereafter "SNL 2013 Coal Retirement Study"), page 14.

A December 2013 SNL study analyzed the combined economic pressures from MATS compliance and other factors (including low natural gas prices, wholesale power prices and demand forecasts). SNL estimates that an additional 16.9 GW is 'at risk" of retirement, with that amount decreasing to 15 GW if average natural gas prices are 50 cents/MMBtu higher than the base case and increasing to 22.3 GW if average natural gas prices are 50 cents/MMBtu lower than in the base case [by 2016]. [84] Most of the coal-fired capacity identified as 'at risk' of retirement by SNL is located in parts of the Midwest and the Southeast, as shown in Figure 16, reproduced from the SNL study. These 'at risk' units are older, smaller and worse performing compared to the average coal fleet overall. This capacity has an average unit size of 102 MW, an average age at retirement of 51 years old, and an average capacity factor of 51 percent.[85]

[84] SNL's report identified 323 GW, but included the 9 GW that had been retired in 2012. As of the start of 2013, SNL identified 314 GW of coal plants in operation as of the beginning of 2013. Of this capacity, 13 GW are not "EGUs," and therefore are not subject to MATS regulations. SNL identified 113 GW of existing coal-fired capacity "which appear to need some retrofits for MATS compliance but have neither announced specific plans for major retrofits nor firm retirement plans." SNL 2013 Coal Retirement Study, page 12-16.

SNL's analysis of announced retirements plus capacity at-risk of retirement is generally consistent with February 2014 study published by the Brattle Group, which identifies additional announced retirements totaling 25 GW in 2014 through 2016, as a result of the combined effects of low wholesale electricity prices and the cost of compliance with pollution-control equipment. This report summarized coal-plant retirements by year: Actual retirements in 2012 (9.0 GW) and 2013 (6.0 GW), totaling 15 GW. Announced additional retirements in 2014 (3.5 GW), in 2015 (16.9 GW), and 2016 (4.6 GW, for a total of 25 GW between now and the end of 2016. Martin Celebi, Brattle Group, "Coal Plant Retirements and Market Impacts," February 5, 2014.

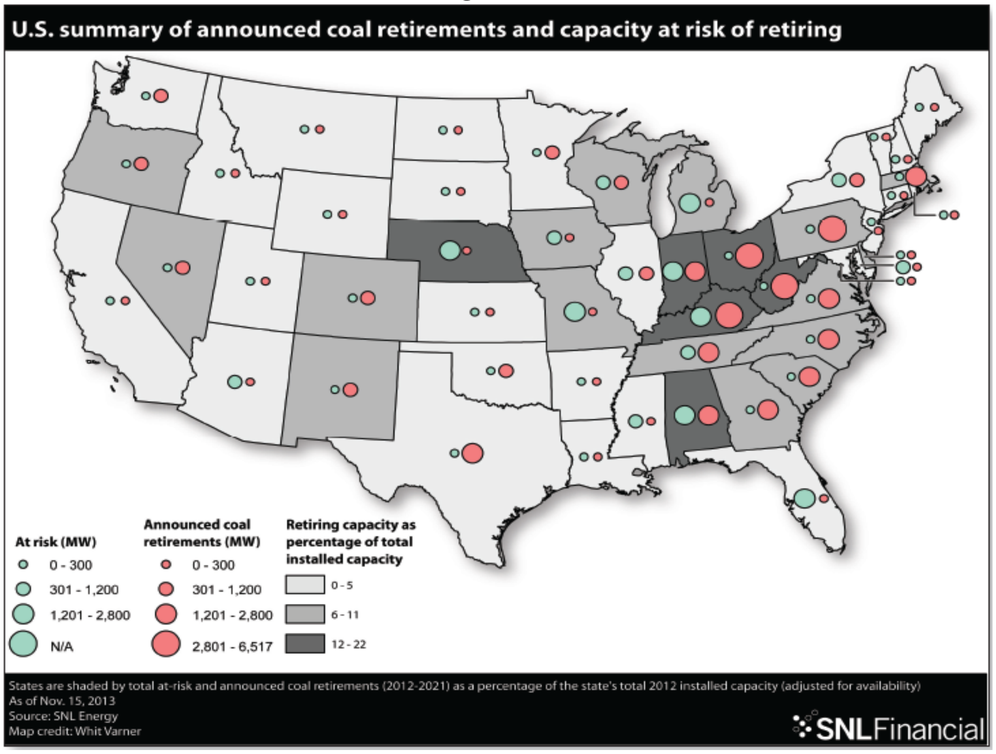
[85] SNL 2013 Coal Retirement Study, Figure 22.

Table 4
Operating Statistics for 'At-Risk" Coal Retirements for Select Regions

	2011 Capacity Factor	Average Heat Rate	Average Age at Retirement	Average size (MW)
MISO (Midcontinent)	52.29	11,598	51	75
PJM (MidAtlantic and Midwest)	40.51	11,414	53	67
Southeast	38.11	10,527	50	169
AZ/NM (Arizona and New Mexico)	65.15	10,953	39	192
SPP (Southwest)	61.44	11,065	48	97
Central	64.79	10,679	60	144
All regions	51.19	11,138	51	102

Source: SNL 2013 Coal Retirement Study, Figure 22.

Figure 16



Source: SNL 2013 Coal Retirement Study. The note on the bottom of the chart reads: States are shaded by total at risk and announced retirements (2012-2021) as a percentage of the state's total 2012 installed capacity (adjusted for availability), as of Nov. 15, 2013.

By now, electric companies and grid operators affected by these retirements have been planning to assure compliance as well as system reliability for many years.[86] According to EIA, as of the end of 2012, "70% of the U.S. coal generating capacity already had the appropriate environmental control equipment to comply with the MATS and allow their operation past 2016. Another 6% plan to add control equipment, while 8% have announced plans to retire. Owners of the remaining 16% are faced with the decision of upgrading or retiring their plants."[87]

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[86] See, for example, M. Bradley, S. Tierney, C. Van Atten, and A. Saha, "Ensuring a Clean, Modern Electric Generating Fleet while Maintaining Electric System Reliability," Fall 2011 Update, November 2011; NERC, "2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations," October 2010.

[87] EIA, "Coal-fired power plant operators consider emissions compliance strategies," March 28, 2014.

The most recent long-term reliability assessment published by NERC indicates that reserve margins will be adequate in upcoming years in all parts of the country, with two notable exceptions: ERCOT (the TRE reliability region in Texas) and the MISO region.[88]

In ERCOT, for example, relatively near-term resource adequacy issues have been headline news for several years, with different parties expressing views about the need for changes in the wholesale power market design (which is an "energy-only" market) to assure new investment in generating capacity.[89] This debate is separate from the state's response to the MATS rule. In its recent analysis of at-risk generating assets, SNL found "no units in ERCOT were identified as at risk under the SNL base case…"[90] ERCOT's regulators, grid operator and stakeholders are working on solutions to address these low-reserve-margin issues, including instituting additional market-design changes, demand-response and other actions.

At the end of 2013, MISO issued a report summarizing power plant owners' plans for unit retirements, and indicated that "25 coal-fired units, representing 8.2 GW of capacity, or about one-eighth of the MISO coal fleet capacity, have yet to determine whether they need an additional year to comply with MATS."[91] MISO's summary indicated a potential shortfall of capacity by 2016 but only if all of that capacity retired and no significant steps end up being taken to increase additional demand-response, energy efficiency, incremental generating capacity, and/or transmission additions. The SNL analysis of 'at risk' capacity identifies 6 GW in MISO, with that capacity at small, old, and inefficient units.[92] Some have offered suggestions

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[88] NERC, "2013 Long-Term Reliability Assessment," December 2013, page 2 and Figure 2 (page 6).

[89] For example, "ERCOT projects that reserve margins will fall to 9.8% by 2014, substantially below its current reliability target of 13.75%. Reserve margins will decline even further thereafter unless new resources are added. Generation investors state that a lack of long-term contracting with buyers, low market heat rates, and low gas prices in ERCOT's energy-only market make for a uniquely challenging investment environment. In response to these concerns, the Public Utility Commission of Texas (PUCT) has implemented a number of actions to ensure stronger price signals to add generation when market conditions become tight…. The key question is whether market prices will be high enough to support entry at an acceptably high reserve margin and associated reliability level." Samuel Newell, Kathleen Spees, Johannes Pfeifenberger, Robert Mudge, Michael DeLucia, Robert Carlton, "ERCOT Investment Incentives and Resource Adequacy," June 1, 2012.

[90] SNL 2013 Coal Retirement Study, page 17.

[91] MISO's "3rd Quarter 2013 EPA Survey Update," November 13, 2013, as reported by Jonathan Crawford, "More than 8 GW of MISO coal capacity still undecided on compliance path for EPA mercury rule," SNL Exclusive, November 18, 2013. "An additional 24 coal-fired units in MISO, accounting for 4.1 GW, that were listed as needing a one-year extension to meet the MATS emissions limits were identified as not having submitted an extension request to regulators for approval. The survey had a participation rate of 98.5%, with 1 GW of MISO's total 66 GW of coal capacity not included in the results….. On the positive side, the survey showed that 35 coal-fired units in MISO, accounting for 11.7 GW, were approved for a one-year extension to comply with MATS. That is out of 84 coal units, representing 24 GW, which could possibly need a one-year extension….This is consistent with calls by the EPA that state regulators be liberal in granting approval of the compliance deadline extension requests."

[92] See prior table. SNL 2013 Coal Retirement Study, Figure 19.

about steps that could be undertaken by parties in the MISO region and states in the near term to ensure adequate reserve margins in 2016.[93] These include: improving joint planning and coordination with neighboring regions with very-high reserve margins (e.g., SPP); increasing the notice that generators must give of their intention to close temporarily or permanently (beyond the current 6-months' notice requirement); and encouraging states to coordinate their plans (e.g., for energy efficiency, demand response) with MISO's.

MISO is taking steps to assuring resource adequacy in light of MATS regulations. MISO is also actively planning for the cost and reliability implications of upcoming Section 111(d) regulations (e.g., for additional retirements beyond those likely to occur before Section 111(d)'s implementation). For example, MISO has recently refreshed its analysis of the impacts of region-wide versus more zonal approaches that MISO states might choose to take with respect to managing their future compliance with Section 111(d), and concluded that a more flexible, region-wide approach may lower the overall cost of compliance.[94] This latter analysis does not specifically assess reliability implications of compliance strategies, but it nonetheless invites cooperative approaches to design compliance schedules and pathways in light of the realities of interstate electricity market operations and reliability considerations.

In both MISO and ERCOT (as elsewhere in the nation), there are at least five years before the full effect of implementation of Section 111(d) will occur. States will have many tools and flexible approaches to use in planning for compliance with GHG emission limits, and addressing reliability and other concerns. For example, MISO and ERCOT have significant amounts of underutilized natural gas combined-cycle capacity whose more-frequent dispatch could absorb some of the generation needed in those regions to comply with Section 111(d). (See Figure 6.) Many states in the MISO region rely on integrated resource plans to assure resource adequacy, and these states can take steps in near-term planning cycles to assure both adequate capacity and generation that emits lower CO_2 emissions. As a single state RTO, ERCOT and Texas regulators have demonstrated an ability to take aggressive action to implement policies deemed to be important for the state.[95]

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[93] For example: John Moore, NRDC, "We Can Have Both a Reliable Grid and a Cleaner Environment," December 9, 2013. http://switchboard.nrdc.org/blogs/jmoore/we_can_have_both_a_reliable_gr.html.

[94] MISO, "Refresh of MTEP-10 Carbon Analysis," presentation to PAC Meeting, February 19, 2014.

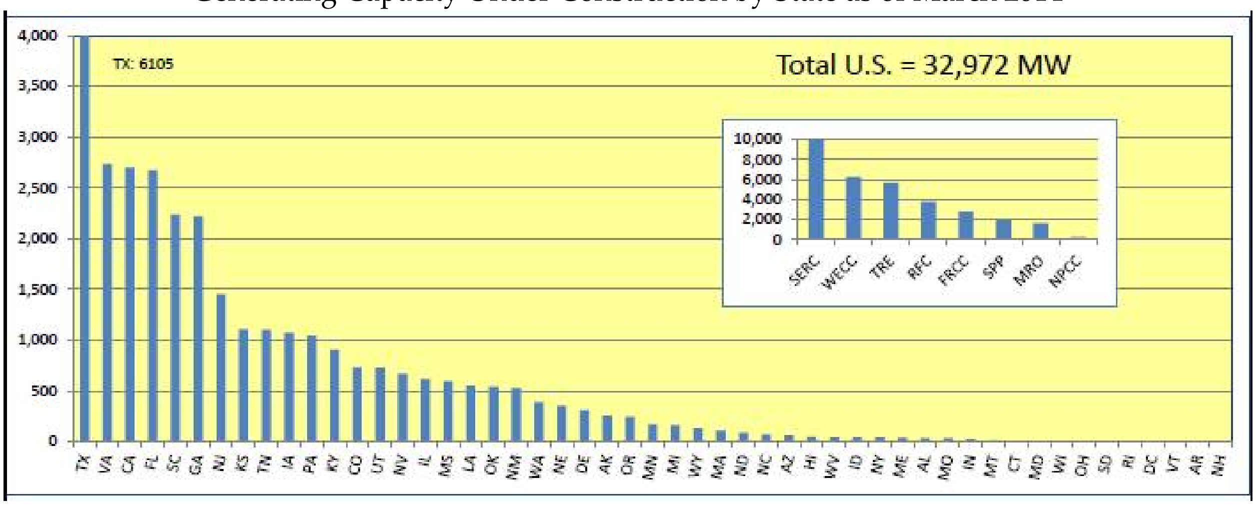
[95] Note that Texas/ERCOT undertook steps in the past decade to create incentives for investment in renewable energy and high-voltage transmission facilities. Today, Texas has the highest amount of wind power capacity (12,355 MW as of the 4th quarter of 2013). It has more wind capacity than the combined amount in the two states with next-highest amount of wind generating capacity

New Generating Capacity Proposals

Given the relatively low price of natural gas, the "fuel of choice" for new power generation capacity planned and under construction by electric utilities and independent power producers has shifted to natural gas and renewable power plants, and away from coal. Figure 17 shows the location of capacity under construction (by state). Half of the power plant capacity under construction is at gas-fired power plants, with another fifth at renewable facilities. There are five new nuclear reactors under construction in the Southeast. Of the other projects in advanced development (e.g., well along in permitting but not yet under construction), approximately one-third of the capacity is at gas-fired power plants, and another 42 percent is at renewable projects. Figure 18 shows the expected net changes in generating capacity from 2013 through 2017, by fuel type and by NERC region. These data reflect the effect of new plants under construction or planned (especially natural gas-fired capacity and renewable projects), as well plant retirements (especially coal, oil, and nuclear retirements).

Figure 17

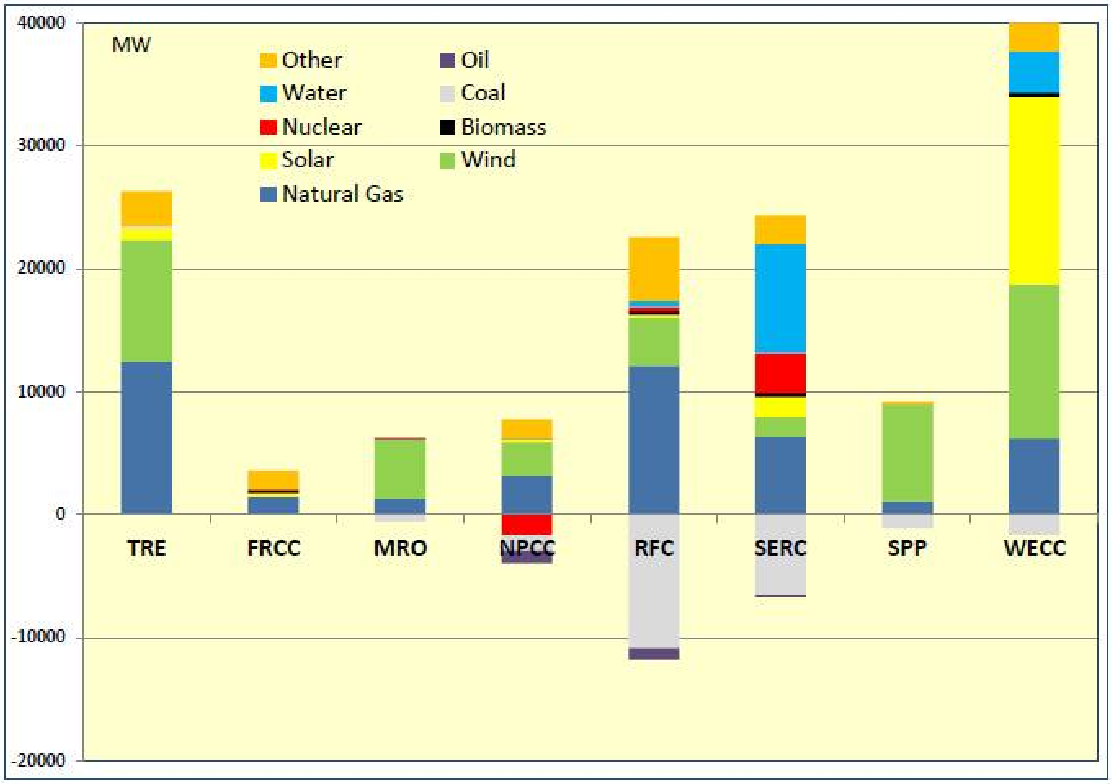
Generating Capacity Under Construction by State as of March 2014



Source of data: SNL Financial

(California, with 5,830 MW, and Iowa, with 5,178 MW). American Wind Energy Association, "U.W. Wind Industry Fourth Quarter Market Report, 2013," page 6. Since 1999, when Texas restructured its electric industry, there has been $14.3 billion investment in transmission, with 9,141 new circuit miles of transmission improvements, with another 2,558 circuit miles and $3.7 billion of planned transmission. ERCOT Quick Facts, 2014. Currently, Texas has 5,833 MW of power plants under construction, and another 1,671 MW in advanced development, most of which is scheduled to come on line in 2014 and 2015. Of this, 3,940 MW is gas-fired capacity. Charlotte Cox, "Nearly 6 GW of capacity under construction in ERCOT, with 42 GW planned," SNL Data Dispatch, February 26, 2014.

Figure 18
Changes in Capacity by Fuel and by NERC Region from 2013 to 2017
(Showing Capacity Additions and Retirements)



Source of data: SNL Financial (as of March 2014)

Implications of the Changing Electricity Resource Mix

The significant changes underway in the electric industry (and described above) set the stage for states' planning for compliance with Section 111(d). To a large degree, many of these changes create breathing room for compliance with upcoming GHG regulations while also maintaining electric system reliability.

Around the country, the changing conditions reflect the combined effects of low natural gas prices, significant under-utilized capacity at existing gas-fired power plants around the country, relatively slow demand growth, continuing opportunities for cost-effective energy efficiency, retirements of older and less efficient coal-fired generating capacity, new natural-gas-fired and renewable energy capacity under construction, and substantial progress toward compliance with MATS by 2016.

The conditions create opportunities for states to maintain system reliability as they plan for compliance with Section 111(d). For example, the presence of under-utilized capacity at existing gas-fired power plants and the outlook for relatively low natural gas prices allow for a relatively affordable pathway to lower GHG emissions, but doing so must be accompanied with advanced planning to assure that natural gas supplies can be delivered and/or stored reliably as electric systems increase their reliance on natural gas. (New England has already had to accelerate its planning to respond to this type of situation while assuring reliable system operations.[96]) Federal regulators and policy makers, grid operators, and many others are focusing on this question of gas-deliverability and harmonization of electric and gas markets.[97] Continued attention to this issue will be important for reliability, regardless of the implementation of Section 111(d).

Similarly, new gas-fired power plants, new renewable projects, and new nuclear capacity additions will further support reliable compliance with Section 111(d). That said, states (and the federal government) should not assume that zero-carbon generating capacity at existing nuclear stations will automatically be available in the future, especially at merchant nuclear plants located in organized markets which are facing significant financial pressure to remain in operation.[98] Planning for reliable and affordable compliance with Section 111(d) should proactively address market reforms and other policies (including design of SIPs) to retain zero-carbon electricity supplies.[99]

In the parts of the country – like MISO and ERCOT – with pre-existing reliability challenges, Section 111(d) will only exacerbate that situation if nothing is done to address them. Clearly,

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[96] ISO-NE has for the past two years focused attention on ways to ensure winter reliability in an electric system with high reliance on natural gas, pipeline capacity constraints, and lack of incentives in the market design to ensure gas-fired generators have fuel to allow them to operate.

[97] See, for example, NERC, "2013 Long-Term Reliability Assessment," December 2013, page 2 and Figure 2 (page 6); Questions of the leadership of the House Energy and Commerce Committee to MISO, PJM, NYISO, and ISO-NE, March 27, 2014; FERC notice of proposed rulemaking on Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities, 146FERC¶61,201, 18 CFR Part 284, Docket No. RM14-2-000, March 20, 2014; Testimony of Acting Chair Cheryl LaFleur and Commissioners Philip Moeller, John Norris and Tony Clark before the House Energy & Commerce, Subcommittee on Energy and Power, valuating the Role of FERC in a Changing Energy Landscape, December 5, 2013.

[98] See my forthcoming paper: S. Tierney, "Today's Nuclear Fleet: What Role in the Nation's Clean, Affordable and Reliable Power Strategy?"

[99] See further discussion below on "outside the fence" actions to reduce GHG emissions.

the industry, state and federal regulators, grid operators, and many other stakeholders are working to address these pre-existing reliability challenges, through a wide range of solutions. These options include potential market reforms, new power plants, new power lines, new gas transmission, more efficient use of existing transmission and distribution systems for electricity and gas, increased investment in demand-side measures, and other things.

Section 111(d)'s compliance period is far enough in the future that there will be time for states and regions to transition toward lower GHG emissions while retaining electric reliability. And, as described previously, Section 111(d) affords broad flexibility to the states to respond to upcoming GHG emissions requirements in a way that preserves electric system reliability.

Planning for Compliance with EPA Guidance Under Section 111(d) of the CAA

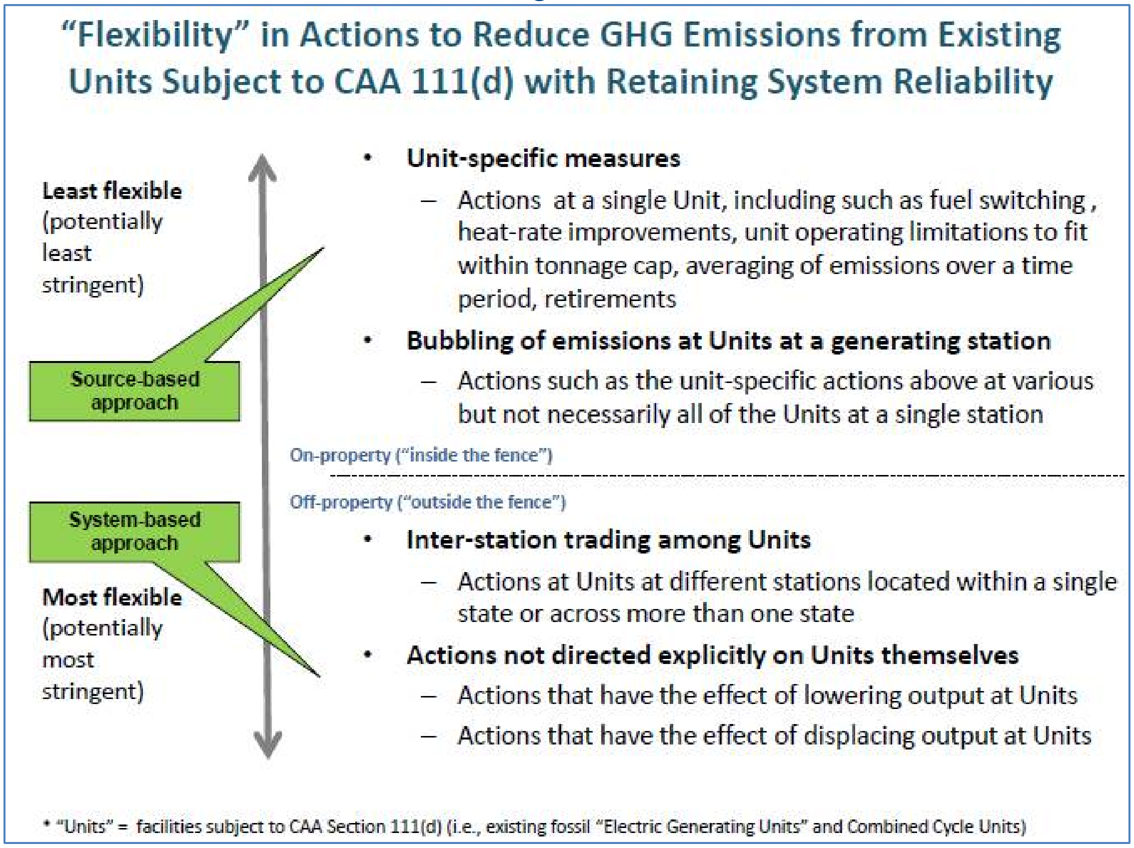
Breadth of Options Available to the States in Developing Section111(d) SIPs

Even in advance of EPA's proposed guidelines (June, 2014), it is already clear that states will have discretion to consider and propose a wide range of options as part of their plans. EPA officials have signaled their intention to allow each state to submit a SIP that enables them to comply with EPA's guidance and tailor their approach to meet multiple state-specific goals, including affordable and reliable electricity supplies.[100]

It is likely that as long as a state is able to demonstrate that its SIP is at least equivalent to EPA's guidance (in terms of reducing GHG emissions from affected power plants), then that state will have significant flexibility in developing its preferred package of policies. For example, SIPs may create incentives for EGUs and NGCCs to reduce emissions "within the fence" line of the covered units themselves. SIPs may include elements that affect actions occurring "outside the fence," where there is a strong connection between those actions and emission reductions at plants covered by Section 111(d). (See Figure 19.) This combination of options creates significant opportunities to plan for reliability while also planning for cost-effective GHG emissions reductions.

[100] For example, remarks of Administrator Gina McCarthy, Acting Administrator for Air and Radiation Janet McCabe and Senior Air Advisor Joseph Goffman at the meeting of the National Association of Regulatory Utility Commissioners, February 7th and 11th, 2014.

Figure 19



Inside the Fence Options

"Inside the fence" actions differ in terms of engineering, cost and feasibility of potential GHG reductions. For example, Dr. James Staudt has identified two categories of actions that can accomplish GHG emissions reductions at existing coal plants: (a) heat rate improvements at the units, which improve the efficiency of the boiler and/or steam plant (in terms of the amount of fuel it needs to burn to generate a unit of electricity), or reduce auxiliary loads at the station; and (b) conversion to a less carbon-intensive fuel, by fuel-switching, co-firing and/or reburn approaches.[101] These engineering-based approaches all focus on reducing a plant's rate of GHG emissions relative to its production of electricity.

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[101] Dr. James Staudt, "Reducing CO2 Emissions from Fossil Fuel Power Plants," presented to the Bipartisan Policy Center workshop on Section 111(d), December 6, 2013. Dr. Staudt has identified the various engineering options for reducing CO_2 emissions from existing coal plants: (1) "Potential Approaches for HR [heat rate] Improvement: Coal Drying (esp., lignite coals); Variable Speed

States seeking these types of engineering approaches could require each affected EGU or NGCC to reduce its emissions by a certain percentage, or meet a maximum emission rate for CO_2/MWh. A state could impose a common standard to all plants in a category of EGUs, or it could tailor the requirements to particular conditions at different plants (reflecting, for example, their remaining useful life, or their role in providing local reliability).

The Department of Energy's National Energy Technology Laboratory ("NETL") has studied the opportunities for "inside the fence" power-production efficiency improvements, and has estimated that they could improve power plant performance (and thereby reduce coal combustion and GHG emissions) in the range of 1 percent to as high as 12 percent, depending upon the particular set of engineering actions taken at different coal-fired facilities.[102]

Other SIP approaches that could lead to "inside the fence" GHG reductions at EGUs and NGCCs would include modifications to the operating permit of particular plants so as to limit the dispatch and generation output of one or more units. It is not uncommon for power plants to have certain operational limits. Sometimes these limit the unit's overall annual output to an amount equivalent to 30 days of output at full power.[103] Or the unit may be dispatched only when local system reliability requirements demand operation of the generating unit (such as shortage events in the summer or winter period).[104] Such inside-the-fence operating constraints

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Drives; Centrifugal to Axial fan conversion; Steam turbine modifications; Intelligent soot-blowing system; New APH seals; Repair boiler casing and duct in-leakage; Condenser cleaning. [2] Using less Carbon-Intensive Fuels: Conversion (convert to 100% gas), with a capital cost of ~$80/kW (with gas on site); Cofiring/Reburning (10-15% gas) Modest cost (somewhat higher for reburn), assuming gas is on site, with co-benefits from reducing NOx emissions as well."

[102] A recent study by the NETL evaluated four efficiency improvement projects, the three of which are 'off-the-shelf' technologies: 1. Coal Pulverizer Improvement; 2. Condenser Improvement; 3. Steam Turbine Upgrade; and 4. Solar Assisted Feedwater Heaters. NETL's analysis found opportunities to reduce GHG emissions in the range of 1.7 to 6.9 percent, with the highest reduction potential at less-efficient power plants. NETL, "Options for Improving the Efficiency of Existing Coal-Fired Power Plants," DOE/NETL-2013/1611, Final Report, April 1, 2014, pages 1-4. Prior NETL studies examined the effect of efficiency improvements: NETL, "Reducing CO2 Emissions by Improving the Efficiency of the Existing Coal-fired Power Plant Fleet," DOE/NETL-2008/1329, July 23, 2008. By examining the efficiency of the top performing coal-fired power plants relative to the efficiency level of the fleet on average, NETL calculates that if changes could be made across the fleet to bring all of the plants up to the top 10 percent performance level, then the CO2 emissions associated with a constant level of MWh generated could be reduced by approximately 12 percent. This conclusion was further examined in NETL, "Improving the Efficiency of Coal-Fired Power Plants for Near Term Greenhouse Gas Emissions Reductions" (DOE/NETL-2010/1411), April 16, 2010. NETL concluded that the use of a combination of aggressive refurbishment and improved operation and maintenance at existing coal plants could improve the average fleet's overall efficiency.

[103] This approach was used in the air permit approvals issued in 1999/2000 by the Massachusetts Department of Environmental Protection for capacity expansion at Mystic Station, in which a new 1500-MW NGCC was permitted to operate in conjunction with imposition of 30-day operating limits on several other older generating units that also existed at the same station.

[104] For example: Several years ago, Exelon Corporation decided to retire units at two generating stations in Pennsylvania (the Eddystone and Cromby units) due primarily to economic factors. In its analysis to determine whether such retirements would lead to system reliability problems, the grid operator (PJM) determined that in the absence of transmission upgrades, retirements of

would affect the terms and conditions of plant dispatch, causing the grid operator (e.g., the local vertically integrated utility, or the RTO) to dispatch other power plants to make up for power it might otherwise have wanted to generate at the restricted unit. A state (or an owner of multiple power plants within the state) might find it economically preferable to impose operating limits on Unit A (with relatively high GHG emissions per MWh) and to dispatch Unit B (with higher operating costs but lower GHG emissions per MWh), than to require both Unit A and Unit B to invest in engineering actions leading to heat rate improvements at both. The permit limitation on Unit A would be the action inside the fence of that plant, and the electricity requirements for the system could be satisfied by electricity generation at Unit A and B.

In theory, a state could identify plants that provide some form of important functionality to the system but produce GHG emissions that are relatively expensive to control through one of the types of actions above. The state could introduce a limitation on that unit's output over an annual period of time such that its MWh and GHG emissions would be capped, while retaining its availability during high load periods, and with its MWh replaced at cleaner unit(s) during periods of low or medium electric demand. The latter approach would be one type of tool that states could use to assure that the compliance pathways demonstrated in their SIPs take into account both GHG emissions reductions and reliability concerns.

Outside the Fence Options

A much wider set of cost-effective emissions reductions could result from SIP elements involving actions in the electric system occurring outside the fence of a specific unit subject to Section 111(d).[105]

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those units would lead to violations of security standards. Exelon entered into agreements with PJM and with the state air regulatory office so that the plant could remain on line pending those transmission upgrades, but allowing the units to be dispatched by PJM only when needed for reliability purposes. Prepared Testimony of Kathleen L. Barrón, Vice President, Federal Regulatory Affairs and Policy Exelon Corporation, before the FERC, Reliability Technical Conference Docket No. AD12-1-000 (etc.), November 11, 2011. This agreement was referenced by CATF in its 2011 proposal for "reliability-only dispatch": "to minimize health risks, we propose limiting the operation of any such units to the brief periods when required to preserve reliability, *i.e.,* when no other resource is available to meet the electricity need. Such a targeted "Reliability---Only Dispatch" approach can serve the goals of both the Federal Power Act's reliability framework and the Clean Air Act's express concern for near term reductions of air toxics and maximum protections for public health and the environment…. Through such customized solutions to identified reliability issues and tailored to specific, local circumstances, the Cromby---Eddystone example demonstrates that when a plant must continue to operate for some period due to reliability needs, it can be limited to running only to meet those reliability needs." John Hanger, "Reliability Only Dispatch: Protecting Lives & Human Health While Ensuring System Reliability," Clean Air Task Force, pages 5, 23.

[105] In the example above, Unit B's redispatch to replace power that would otherwise have come from Unit A is an example of an outside-the-fence counterpart action to the inside-the-fence action at Unit A.

Emission Averaging and Carbon Budgets

Many observers have examined the economic and emissions trade-offs associated with engineering-approaches versus more market-based compliance approaches. For example, Dallas Burtraw and Matt Woerman compared the cost to achieve a ton of CO_2 emission reduction through inside-the-fence actions versus outside-the-fence options enabled through a 'tradable performance standard.' Starting with estimates of the cost to accomplish the types of inside-the-fence options, they determined that with the money it would take to accomplish 4 percent reductions in GHG emissions inside the fence, it would be possible to achieve four times the amount of total emissions reductions if power plants were allowed the flexibility to trade emissions reduction opportunities.[106]

They and others[107] have analyzed variations on this approach of allowing a state to comply with EPA guidance by creating a rate-based or mass-based tradable currency, either of which could allow units with a higher level of GHG emissions per MWh to trade with those having a lower-than-average level of GHG emissions per MWh.

The Philips/CATF 2014 study explains how the use of a mass-based standard (converted from an original rate-based standard) has numerous benefits because it overcomes certain market distortions that might arise with use of a rate-based standard alone. "First, the positive price on carbon emissions and lack of production incentives means they would diminish or avoid the previously described emission rebound, seams and longer term regulatory transition concerns associated with most rate-based approaches. Also, they would give states another proven, practical compliance pathway and greater flexibility than if every state were restricted to complying through a mandatory emission rate standard. …Further, the accounting rules required to reflect the impact of new

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[106] A "specific emissions rate improvement averaged over a larger set of generators reduces the actual emissions change. A marginal abatement cost criterion to compare policy designs suggests cost-effectiveness across sources. This criterion can quadruple the emissions reductions that are achieved, with net social benefits exceeding $25 billion in 2020, with a 1.3 percent electricity price increase." Dallas Burtraw and Matt Woerman, "Technology Flexibility and Stringency for Greenhouse Gas Regulations," Resources for the Future, July 2013, executive summary.

[107] For example, Phillips/CATF 2014; Christopher Van Atten, "Structuring Power Plant Emissions Standards Under Section 111(d) of the Clean Air Act – Standards for Existing Plants," MJ Bradley & Associates, October 2013; National Climate Coalition, "Using EPA Clear Air Act Authority to Build a Federal Framework for State Greenhouse Gas Reduction Programs," September 2013.

renewable facilities, energy efficiency programs and nuclear uprates, would be much more straightforward under a mass-based system than a rate-based system."[108]

More generally, mass-based standards can be translated into a total amount of GHG emissions "budgeted" or allowed to occur in a state. A budget could apply to all units collectively within a state, or to groups of units within a state, or to the units in multiple states that have compacted with each other. Chris Van Atten has described how a state budget approach might work: "In proposing a state budget approach, EPA could still develop a rate-based performance standard and then translate that performance standard into state budgets, giving each individual state the choice in terms of whether to impose a rate-based performance standard or state-wide emissions budget. In guidance to states, EPA could: define the appropriate baseline period (i.e., the MWh data used in converting the lbs./MWh standards to tons); determine whether and how future economic growth should be factored into the calculation of the budgets; and define trading rules for states that elect to allow trading as a compliance mechanism."[109]

Demand-side and non-carbon emitting options

States could take action to create incentives specifically aimed at adding and/or retaining zero-carbon electricity supply through adoption of a tradable emission standard ("TES") or clean

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[108] Also, "Rate-based approaches…are typically established so that some covered generating sources have emission rates above the standard and others have rates below the standard. Generating sources with emission rates above the standard must undertake actions to come into compliance. Generating sources with emission rates below the standard have a financial incentive to increase their production, assuming an emission credit trading program, because every additional unit of generating output "earns" that generator additional emission credits which have a financial value under the trading program. In the case of a single blended fossil rate standard covering both coal and gas generation, NGCC units would typically be awarded emission credits whenever they generate output. This would allow gas units to sell power for less than their direct variable fuel and O&M costs. The value of the credits earned by generating additional output partially offsets the unit's variable cost of production, reducing the marginal cost of dispatch and making the unit more competitive with other sources of generation in that power market without comparable production incentives. Such production incentives can lead to unintended adverse consequences….. create what often are referred to as "seams" conflicts at the borders of mass-based trading programs such as RGGI and other mass-based programs, emissions "rebound", and greater difficulty in transitioning to longer term national carbon policies." Phillips/CATF 2014 (pages 8-9, 18).

[109] Also: "States would … have the flexibility to determine their preferred method for meeting their assigned budget, including the option of relying on a system of transferable emissions permits. If states elected to implement a trading program, power plant operators would track their CO2 emissions and surrender an emissions permit for each ton of CO2 released to the atmosphere….. For example, a state could propose to give each company operating in the state a set number of emission permits. Under such a scenario, a regulated utility might advocate for a company-wide emission budget that it could reflect in its integrated resource plan." Christopher Van Atten, "Structuring Power Plant Emissions Standards Under Section 111(d) of the Clean Air Act – Standards for Existing Plants," M. J. Bradley & Associates, October 2013, pages 17-18.

energy standard ("CES"). When applied to owners of generating units in an area, the TES could be a mechanism through which generation of zero- and low-carbon electricity by suppliers (old and new) would create carbon-free electricity credits, for sale to others. For example, a state (or a group of states) could set assign a common target CO_2/MWh to *all* generating units in the state, and then allow generators with different CO_2/MWh emissions rates to buy/sell their CO_2-emission permits. A provider of energy efficiency or demand-side measures could similarly generate CO_2-emission permits. It would be important that such a standard be at or below the emissions rate achievable by NGCCs so as to avoid potential wholesale price distortions that would result from natural gas units generating rate credits by offering a price below their variable cost of generation (as could arise as described above by Phillips/CATF 2014).

By contrast, a state could apply the CES to sellers of retail power supply (e.g., load serving entities ("LSEs")) to demonstrate that their overall supply portfolio satisfies a standard emissions amount (in much the same way that an RPS requires LSEs to include renewables as a percentage of their supply portfolios). A CES could cover all existing and new generation, thus allowing sellers of zero-carbon supply to find revenue streams to remain in and/or enter the market.

Allowing zero-carbon resources to capture the economic value of that attribute through efficient market-based transactions with other generators provides the state with the ability to arrive at a least-cost, reliable pathway toward overall electric system compliance.

RTO Dispatch Constraint

Another recent variation on the outside-the-fence approach has been suggested for one multi-state RTO (or Independent System Operator ("ISO")) region. In this approach, the RTO would expand the criteria it uses to determine the dispatch of power plants so that in addition to security-constrained economic dispatch, it would also use a total system-wide constraint on CO_2 emissions. As described by its authors, this concept includes the following elements:

> Translate EPA requirements into ISO-level targets on CO_2 emissions, ideally with a single long-term target (*e.g.* X% reduction over 2000 level, by 2030). Short/intermediate term targets may be necessary to guide the "emissions path," but could limit flexibility of meeting the targets and possibly be less cost effective.
> ISO sets an initial path of "carbon values," that are used in dispatching (based on

> emissions profiles and bid offers) to reach the expected regional target. Plant dispatch minimizes total cost while meeting reliability and CO_2 constraints. The resulting power market prices, paid by load, reflect the emission constraints. Generators are charged the per-unit carbon value for their CO_2 emissions. Revenues collected are returned to load on a non-variable basis (maintaining proper price signals for demand-side resources). ISO adjusts carbon value path carefully when updated projections of emissions deviate significantly from original assumptions.[110]

These various mass-based approaches allow for cost-effective and administratively efficient means to reduce GHG emissions across the power plants dispatched in a system. And they allow for system conditions, such as reliability considerations, to factor into the manner in which the grid operator dispatches its plants to meet system requirements in regions with organized wholesale electricity markets.

Figure 20 shows (with color shading) the parts of the U.S. where an RTO (or ISO) is the grid operator and administrator of an organized wholesale market.[111] In these areas, the RTO has responsibility for centrally dispatching power plants that are owned or controlled by market participants (e.g., utilities (including investor-owned, coops, publicly owned utilities) and IPPs) in that region.[112] In states (or parts of states) which are not part of an RTO, the utility typically is responsible for centrally dispatching the power plants it owns or controls. In some states with a traditional vertically integrated electric industry structure, most if not all of the generating capacity is owned by utilities. The states with more than two-thirds of their generation produced at utility-owned power plants are shown with a pattern (dotted) on Figure

[110] Judy Chang, Jurgen Weiss, Yingxia Yang, Jon Brekke, and Will Kaul, "A Market-based Regional Approach to Implementing EPA's GHG Emissions Regulation," Brattle Group and Great River Energy, January 2014.

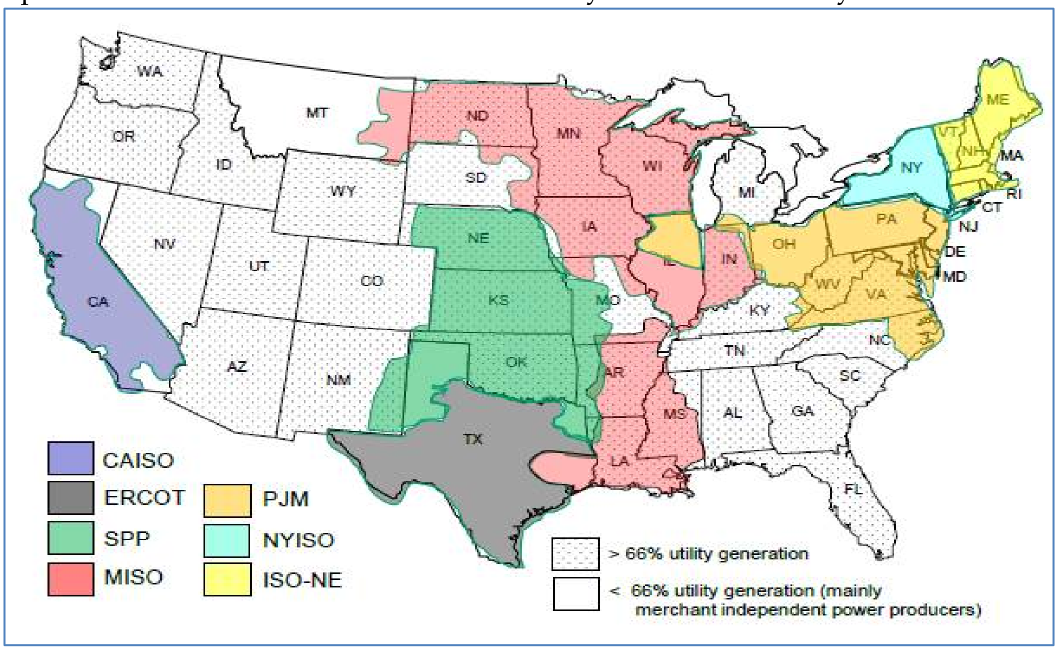
[111] "Presently, RTOs/ISOs geographic footprint covers approximately 2/3rds of the nation, encompassing regions that cover all or parts of 38 of the 50 states plus the District of Columbia. ISOs/RTOs serve approximately 75% of national demand." ISO/RTO Council, "EPA CO_2 Rule – ISO/RTO Council Reliability Safety Valve and Regional Compliance Measurement and Proposals," January 31, 2014.

[112] "ISOs/RTOs centrally dispatch power plants within their footprint based on the marginal cost of operation of each individual unit as reflected in bids submitted to the ISO/RTO on a day ahead basis.[fn] By dispatching generation resources across the I ISO/RTO footprint based on the marginal cost to produce the next MW of electricity, the economic efficiencies of the generation fleet is maximized for each hour of the operating day across the entire RTO footprint.[fn] Supply bids submitted by generators effectively internalize environmental compliance costs while still ensuring least cost compliance with environmental requirements.[fn] The regional centralized dispatch undertaken by ISOs/RTOs is known as Security Constrained Economic Dispatch (SCED)." ISO/RTO Council, "EPA CO_2 Rule – ISO/RTO Council Reliability Safety Valve and Regional Compliance Measurement and Proposals," January 31, 2014.

20. Figure 21 shows the ranking of states according to their reliance of utility-owned (and not IPP-owned) generation.

Figure 20

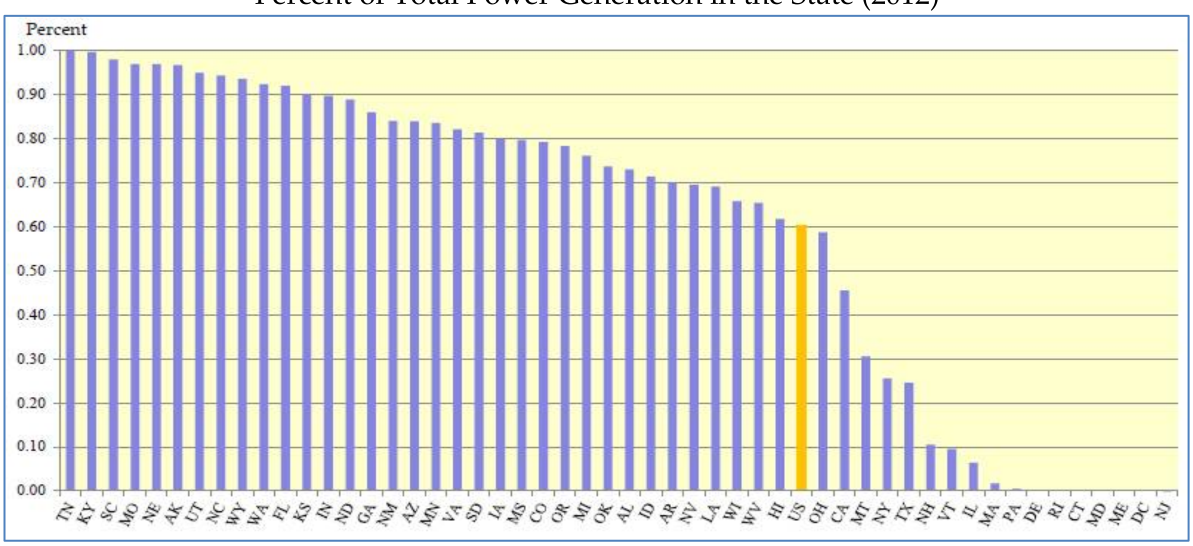
Footprint of RTOs and States' Reliance on Utility versus Non-Utility Power Generation



Source: EIA Generation by Type of Producer and by State, 2012.

Figure 21

States' Reliance on Utility-Owned Generation as a Percent of Total Power Generation in the State (2012)



Source: EIA, EIA Generation by Type of Producer and by State, 2012.

Recent modeling by Bruce Phillips for the CATF examines how two alternative policy designs for an emissions standard would work in a regional dispatch. As shown previously in Table 1, the "CATF 2.0" options that they modeled were: (a) a single mass-based standard applicable to all fossil power plants, and (b) an alternative that has a mass-based budget for emissions from coal-fired power plants and a rate-based standard for emissions from gas-fired power plants (which they have called the "Mass-Based Coal" budget as a short hand name).[113] Phillips' analysis found that both "approaches would reduce emissions through a mix of compliance actions: by reducing the heat rates (and consequently the emission rates) of coal units; displacing high emission rate coal generation with lower emission rate gas generation through an emission credit trading program; retiring coal generating capacity, and reducing electric demand through customer response to higher electric prices. Of these, the emission reductions from fossil dispatch represent the largest single source of reductions, in both cases approximately 70 percent of total compliance…..Heat rate improvements, coal retirements and electric price response comprise the remainder, with approximately 10 percent, 15 percent and 5 percent respectively."[114] The analysis also concluded that these policies would lead to relatively similar changes in generation and capacity mix: "Under the mass-based coal case, 42 GWs of coal capacity retire due to the policy (that is, relative to what would otherwise be expected in 2020), average national coal capacity factors decline from 67 to 58 percent and average national NGCC capacity factors increase from 48 to about 65 percent. Under the mass-based fossil case, 37 GWs of coal capacity retire, average national coal capacity factors decline to 58 percent and average national NGCC capacity factors increase to 63 percent."[115]

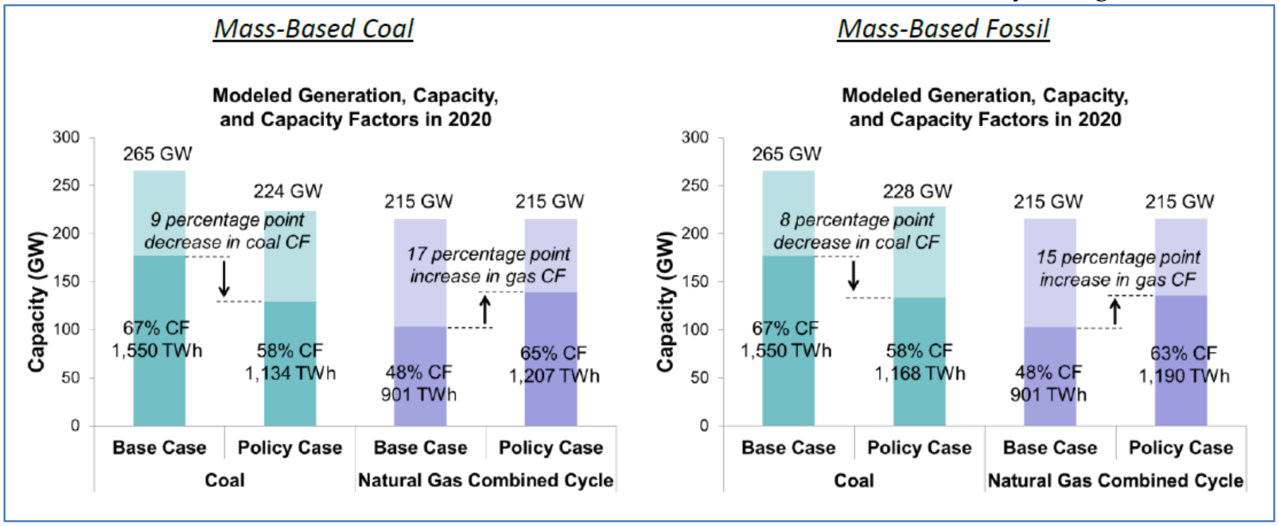
[113] Phillips/CATF 2014, page 17.

[114] Phillips/CATF 2014, page 21.

[115] Phillips/CATF 2014, page 21.

Figure 22

Modeled Changes in Generation Output, Capacity Retirements and Capacity Factors of Coal-Fired and Gas-Fired Power Plants under Two Alternative CATF Policy Designs



Phillips/CATF 2014, page 22.

This analysis suggests that there will be capacity retirements that are manageable, especially in light of the existence of underutilized NGCC capacity in all regions of the country, along with inherent flexibility in the Section 111(d) framework that will allow states to tailor their SIPs to local conditions and reliability requirements. ,

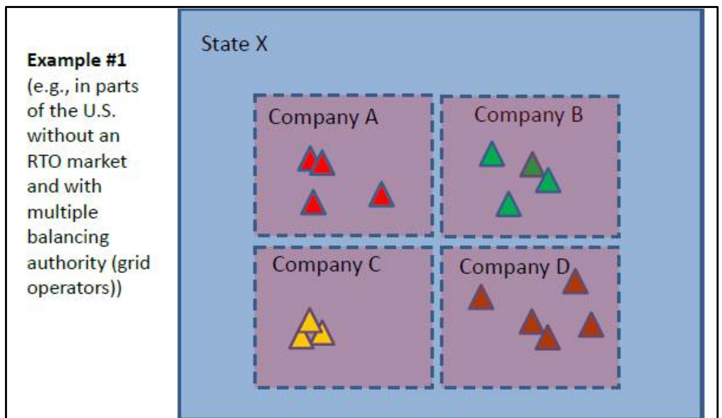
Outside-the-Fence Models Approaches: Examples to ensure reliable and economic compliance in states with different electric industry structures

Because states have different electric industry structures that affect how groups of power plants are dispatched to supply electricity at different times during the year, states will likely seek to take this factor into account as they consider different options for and inside-the-fence and outside-the-fence compliance approaches.

For example, there are two key features of industry structure: (1) presence or absence of an RTO; and (2) the extent to which utilities versus merchant generators (IPPs) dominate the power generation – seem relevant for how a state might consider structuring its SIP to include relatively cost-effective outside-the-fence policy elements. These two features essentially are proxies for the extent to which power plants owned by different entities participate in a common system for generation dispatch within a state (or across a region).

Consider the following examples as ways that a state could develop an economically efficient tradable compliance mechanism and in so doing, support more cost-effective, reliable compliance with GHG reduction targets. All of these examples are based on an assumption that EPA will issue state-specific guidance that reflects either a blended target emissions rate for all fossil-fuel generation (EGUs and NGCCs) or a separate one for each fuel, with a multi-year period over which a state needs to make reasonable progress toward compliance. The examples also assume that the state may use a variety of tools to achieve the targeted emissions reductions, many of which accommodate planning to mitigate electric system reliability concerns.

Example 1: Trading Among Power Plants Owned by Common Owner within a Single State: In this example, the state has a traditional electric industry structure, with several vertically integrated utility companies owning power plants in that state. These utilities do not belong to an RTO. Several of the utilities have more than one generating unit subject to Section 111(d) and these units have different emissions rates (CO_2/MWh). A simple trading approach the state could adopt in its SIP would be to allow emission trading across all of the units owned by a single utility. Each owner could determine the set of actions through which it would maintain reliability and bring its fleet into overall compliance with the target. These approaches could include redispatch of existing fossil plants to find the optimal mix of production, investment in a zero-carbon generating source, and/or other actions to produce a blended lbs of CO_2/MWh rate consistent with the state target.

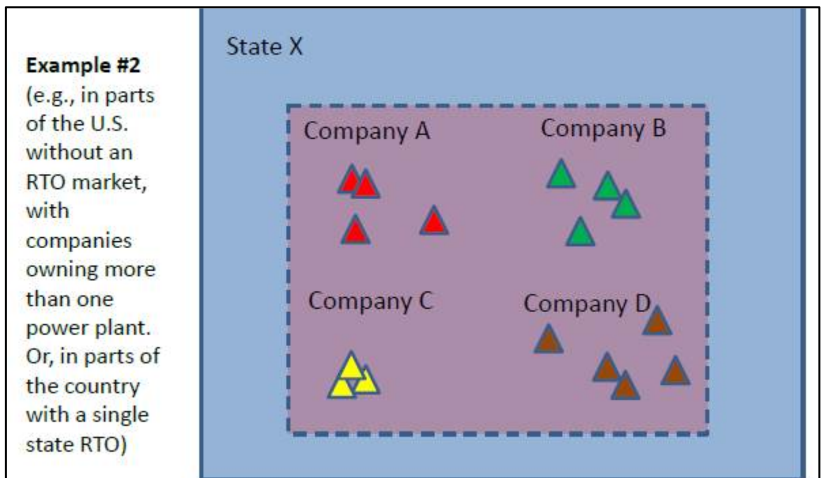


Averaging across units within a power plant Owner's Fleet within a single state

Let's assume further that one of these utilities had recently made investments in one of its coal-fired power plants to enable it to comply with MATS. To retain the economic and reliability value of that investment, the utility would be allowed (through the state's SIP) to operate that plant for more years into the future, as long as these emissions are offset somewhere else in the system. Perhaps this could be accomplished by relatively aggressive investment in energy efficiency to reduce the utility's MWh requirements that would otherwise have been met by its marginal and high-emitting generating unit(s) and in so doing offset the emissions from plants. Perhaps another utility wanted to retain its ability to operate an otherwise relatively inefficient power plant in order to manage an overall resource adequacy issue. This utility could propose a limit on the operating permit of that power plant, in order to maintain it on the system for reliability reasons during seasonal peak energy demand, while also committing to lower output at that plant.

To allow different sets of actions for different utilities that reflected each one's particular circumstances, the state could structure its SIP to give each utility the ability to manage the cumulative emissions associated with its fleet's power generation over a multi-year time period in order to satisfy economic and reliability requirements efficiently while also complying with the necessary GHG emission reductions.

Example 2: Trading Among Power Plants Owned by Multiple Owners Within a Single State. In this example, another state with a similar industry structure (no RTO, power plants owned by multiple companies) decides that it will propose a SIP that would permit intra-state trading among all of the power plants subject to Section 111(d) plants within the state. The state could use the EPA's state-wide target CO_2/MWh rate(s) for that state, and allow owners of plants with emissions higher than that rate to trade with plants lower than that rate. The state could either use the tradable-rate-based model or a mass-based approach, with a ceiling on total emissions during a time period and with tradable allowances that companies were either given for free or allowed to purchase through an auction.



Averaging (and/or trading) across units owned by multiple companies within a single state

Different states in this situation might approach this allowance allocation differently. One might chose to give away for free the allowed statewide average target emissions rate (e.g., CO_2/MWh). The plants with higher-than-average emissions would purchase enough CO_2 credits to accomplish the target blended rate. The generator with lower-than-average emissions could sell off the difference between its actual rate and the target rate allocated to it, without taking any further action. Another generator with economically attractive opportunities to make improvements and/or add low-carbon resources to bring its own fleet average even further below the statewide target would have even more CO_2 credits to sell.

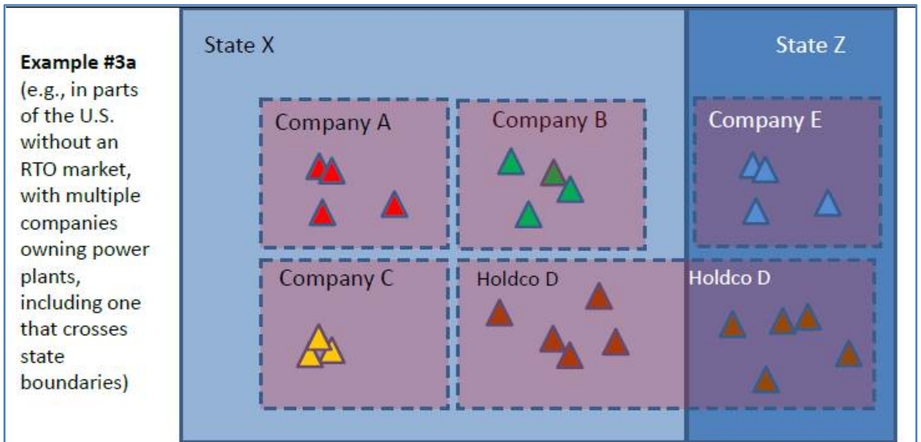
By contrast, another state could decide to allocate higher-than-average emissions credits to one owner of Section 111(d) units with relatively high emissions, and a different allocation rate to another owner, reflecting equity, stranded costs, electricity price impacts and reliability considerations across the different service territories. Another state might decide that each owner of a Section 111(d) generating unit would need to buy all of its needed CO_2 credits (rather than receiving even the average initial allocation for free), and then use the proceeds from the sale of those CO_2 credits to offset consumers' price impacts or to fund energy efficiency program to reduce the overall MWh requirements, achieve CO_2 emissions reductions as a result.

Additionally, the state could choose whether to allocate the target CO_2/MWh rate to only Section 111(d) generating units, to all fossil units, or to all generating sources (including ones with zero carbon electricity production). The former would tend to lead to trading among fossil units only, and the state could accompany this model with other SIP elements (e.g., increased RPS requirements; new nuclear unit upgrade; a new TES or CES) to increase and/or maintain zero-carbon electricity as a displacement of MWh produced at fossil units. The latter would tend to rely on an economically efficient mechanism for lowering CO_2/MWh through creating value for zero-carbon energy options and retaining capacity for reliability and diversity purposes.

A company could manage its own in-state fleet by using its preferred combination of inside-the-fence options, redispatch of its own power plants, procurement of zero-carbon MWh, and purchases/sales of tradable CO_2 credits with other power plant owners in the state. The tradable credit or tradable allowance would end up having a price reflecting economic investments in CO_2 reductions across the state's set of power plants.

Such approaches could accommodate many different operational/reliability issues economically. The utility with potential stranded investment in MATs compliance, for example, could purchase output (and credits) from another power plant owner's lower-emitting but otherwise underutilized generator. The power plant owner that faces a curtailment of natural gas supply during a winter shortage condition could run a unit with higher emissions at that time and offset that unit's CO_2 rate with purchases of a tradable credit from another power plant with lower-than-average emissions. Again, the main point is that states could formulate their SIPs to allow each power plant owner to manage the cumulative emissions associated with its fleet's power generation over a multi-year time period so that the average CO_2/MWh target is met, along with all operating and resource-adequacy requirements necessary for system reliability.

Example 3a: Trading Among Power Plants in Multiple States That are Owned by a Common Holding Company. In this example, electric generating units located in two states are owned by a common parent company (Holding Company D, in the figure) that operates all of its power plants as a single integrated system for resource adequacy, operational security and economic purposes. From the point of view of system operations, Holding Company D dispatches plants in both states according to security-constrained economic dispatch principles, and shares the economic value of that common system with customers in both states. In this example, there are also other utility companies and IPPs (Companies A, B, C, and D) that own power plants in the relevant state.

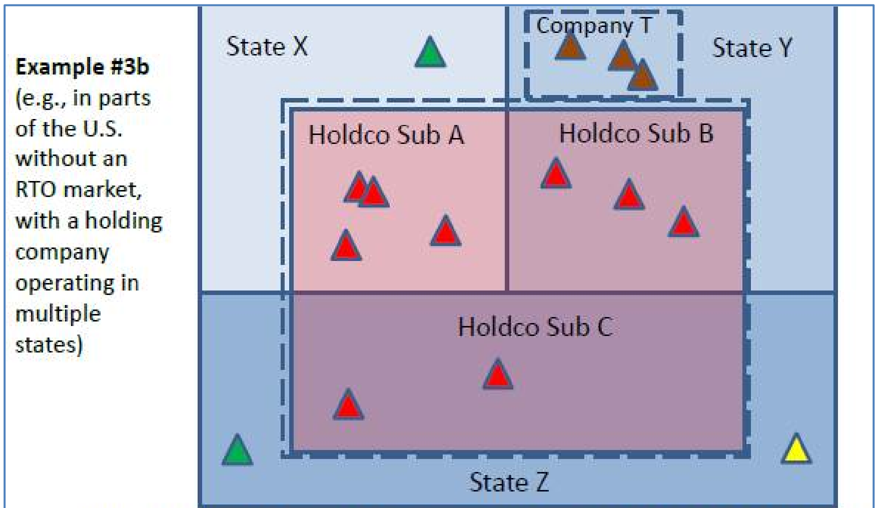


Averaging (and/or trading) across units within a power plant Owner's Fleet within single states, and with an interstate agreement to allow cross-state trading for plants owned by a single holding company operating in the two states

Let's assume that each state has been given a different GHG emissions' rate target in EPA's guidance. Each state decides to include in its SIP a mechanism that allows for trading within company-owned fleets or across companies within a state (as in Examples 1 and 2). But for the holding company, the two states decide that they would like to retain the efficiencies associated with that company's multi-state dispatch. So the two states enter into a formal agreement to allow for interstate trading specifically for Holdco D located in both states, thus enabling it to continue to operate its fleet on a single system basis. (The two states may or may not allow Holdco D to trade with Companies A, B, C, and E.) To the extent that such multi-state dispatch of Holdco's plants means that State X's CO_2/MWh average rate that is higher over the relevant time period than it otherwise would be under single state operation, then the states' agreements would need to establish a mechanism for tracking and offsetting such emissions through deeper reductions in State Y.

This example suggests a way for states to collaborate voluntarily in the design of their SIPs, to tailor elements to fit the structure of their electric industry and to honor long-standing economic and reliability relationships among various utilities and other industry institutions.

Example 3b: Trading Among Power Plants Owned by Multi-State Holding Companies and With the States Having Different Appetites for Other In-State Trading. This example is a slight variation on the same theme as Example 3A. Here, the three states still get different CO_2/MWh targets from the EPA, in light of the different conditions in those states. The three states sharing the holding company agree formally to allow that company's subsidiary companies in the three states to participate in a common interstate CO_2 credit-trading program. In exchange for allowing that flexibility, the states agree to require the holding company to achieve more GHG emissions reductions in its fleet than it would otherwise absorb if each state gave the holding company each state's statewide average CO_2/ MWh target. For power plants owned by entities unaffiliated with the holding company, one of those states allows other trading within the states, but the others do not.



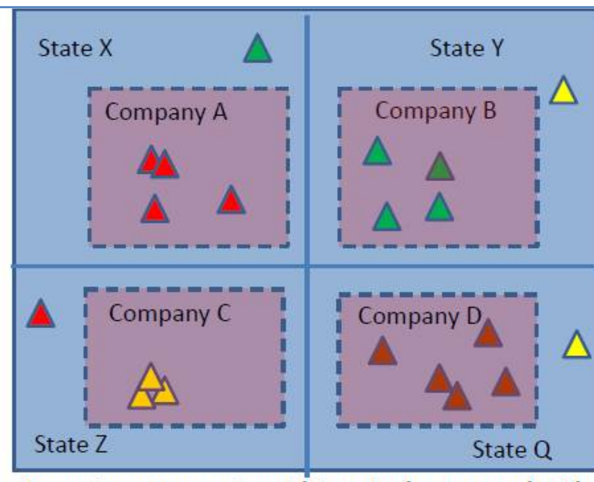
Averaging (and/or trading) across units owned by a single holding company multiple states enabled by an interstate agreement to allow such cross-state trading. No other trading allowed in State X or State Z, but allowed within companies in State Y

The three-state agreement is included in each of the three states' SIPs, and it details the mechanism through which the states will credit/offset/true-up emissions located in one state against the other states' compliance requirements. The three states could establish a multi-state cap over that holding company's generating resources. The holding company has the ability to meet its target through a combination of dispatching its power plants, incremental purchase of power generated at low-carbon resources, energy efficiency, demand response or other actions to reduce CO_2/MWh across the three states. The other company in State Y has the same ability to use its fleet to achieve a blended average emissions rate that complies with EPA guidance for the state.

Again this example suggests tailored strategies to reflect economic, reliability and other conditions unique to a set of states.

Example 4: No Interstate Trading Except for Emissions Associated with a Multi-State Energy Imbalance Market. In this example, the electric companies in a number of states operate as vertically integrated stand-alone utilities, owning generating assets and serving load in a single state. Some of them (e.g., Company A in State X) also own power plants (or contracts for power) in another state (e.g., in State Z) for producing part of the supply for retail customers in the home state (State X). These various approaches have traditionally provided resource adequacy. Each company is interconnected to other utilities in the region through transmission lines, and each company plans for and schedules the dispatch of its own power plants to meet its customers' requirements (load) with operational reliability. Specifically, each company is the grid operator (balancing authority) in its electric system. Because anticipated demand varies in real time from actual demand, the interconnected utilities have entered into an "energy imbalance market" to allow power companies to voluntarily make their generating assets available to the entire region to allow for efficient dispatch of generating units across multiple systems to make sure that the systems have supply and demand in balance at all times.

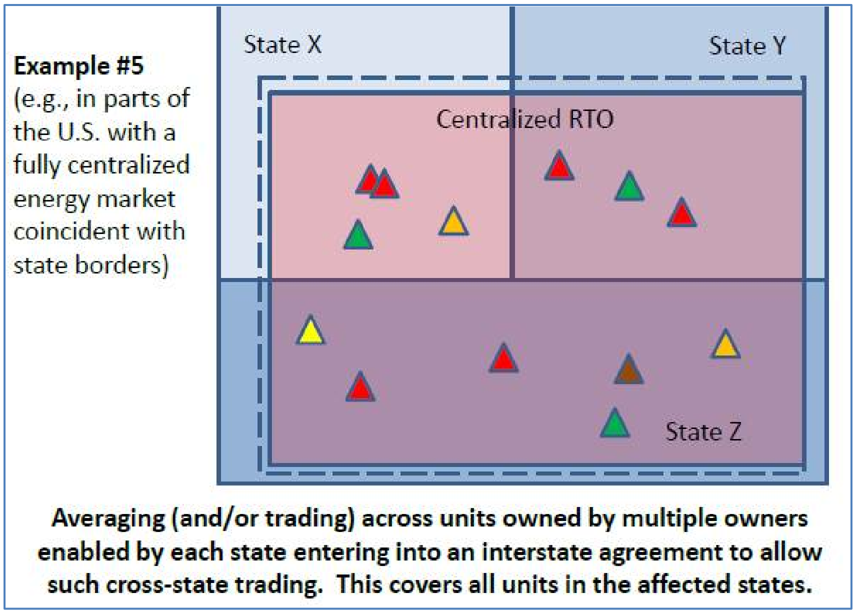
Example #4
(e.g., in parts of the U.S. without an RTO market and with a common energy imbalance system that operates across the multi-state footprint, with some companies owning power plants in more than one state.



Averaging across units within a single state and with multi-state agreement to account for energy imbalance services across the states.

The states in this interconnected region enter into an agreement to allow for the CO_2 emissions associated with such energy imbalances (which are important for both reliable and efficient power supply) to be accommodated within each affected states' SIPs and to credit/offset emissions changes in one state that result from such an interstate energy imbalance market.

Example 5: Multistate RTO. Example 5 depicts a multi-state area, where all of the power plants located in the three states participate in a single RTO. The RTO is responsible for centralized security-constrained economic dispatch of all power plants in the states. The three states seek to retain the economic and reliability benefits of this multi-state RTO, recognizing that CO_2/MWh in one state may be affected by the dispatch protocols of the RTO that affect all power plants in the region.

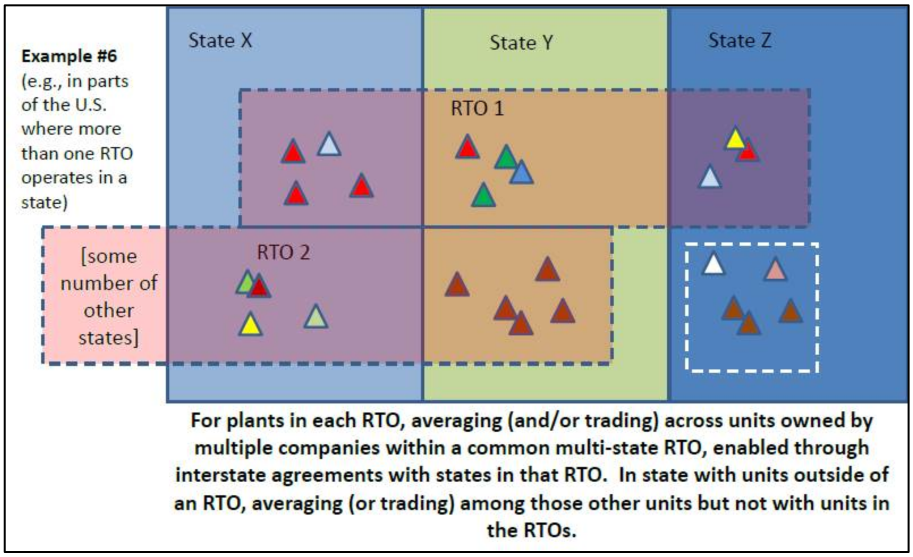


Each of the states includes in its SIP a formal agreement to allow trading across the units in the RTO footprint. The states could work with the RTO to establish the mechanism(s) through which the RTO would introduce CO_2 prices and/or other constraints into the dispatch (e.g., through a shadow price[116] or through actual tradable credits).

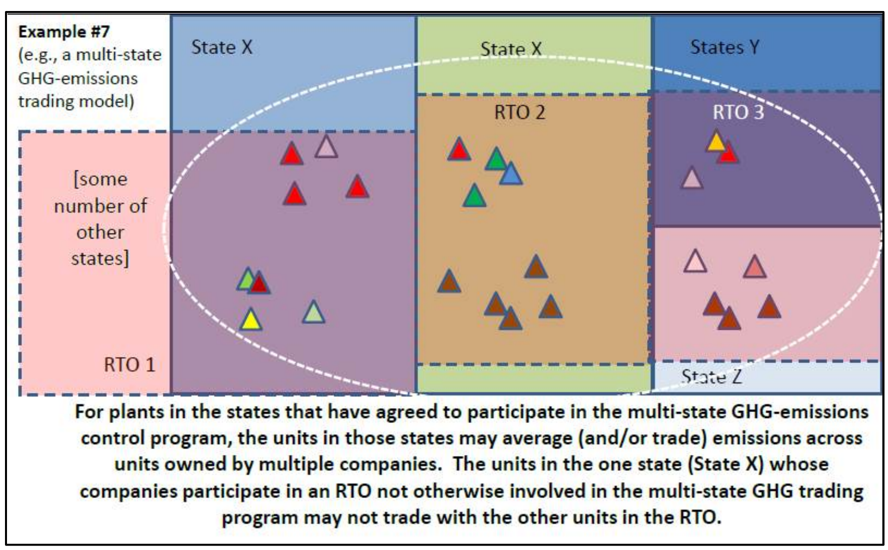
In addition to providing this interstate trading arrangement as part of their SIPs, affected states could also include in their SIPs various other policies – energy efficiency, clean energy standards, more aggressive RPS, contracts with zero-carbon electricity supplies, integrated resource planning with a shadow price on carbon, and so forth – that affect the CO_2 emitted from the fossil plants in the RTO. Together, these approaches respect the regional operational reliability practices, market-based dispatch approaches, and state-specific policy preferences and resource-adequacy approaches.

[116] As an example, stakeholders in MISO are exploring the implications of a CO_2 design that would use a limit on total emissions in the RTO footprint, along with a shadow price to use in security-constrained economic dispatch. Judy Chang, Jurgen Weiss, Yingxia Yang, Jon Brekke, and Will Kaul, "A Market-based Regional Approach to Implementing EPA's GHG Emissions Regulation," Brattle Group and Great River Energy, January 2014. Also, MISO, "Refresh of MTEP-10 Carbon Analysis," presentation to PAC Meeting February 19, 2014.

Example 6: States with Multiple Multi-State RTOs: This example is similar to the prior one, except that one of the states in this region has Section 111(d) power plants located in two different RTOs, each covering a portion of the state. In this example, to the extent that each state seeks to allow its power plants to trade within the RTO market, each state would enter into an agreement to participate in a common trading program, potentially administered by each RTO. The state with electric utilities situated in two RTOs could determine the target CO_2/MWh that Section 111(d) units in each part of the state would need to achieve through the inter-state trading program administered by each RTO.



Example 7: States with Multiple Multi-State RTOs and a Multi-State CO_2 Trading Programs. A final example involves a multi-state region with multiple RTOs and with a multi-state GHG trading program whose boundaries are not coincident with the boundaries of the RTO. The GHG trading program is a mass-based model, using a cap-and-trade system with CO_2 allowances purchased by all fossil generating units (including EGUs and NGCCs). (An example of such an approach is the RGGI program in the Northeast.) In this model, the states have



included in their SIPs their agreements with the other states that participate in the multi-state GHG program. State SIPs would delineate the manner in which the Section 111(d) units within their borders may trade emission allowances (or reductions or averaging) within the program, but not with other units in the portions of the RTO (e.g., RTO 1) where the program is not in effect. Reliability practices, like security-constrained dispatch or capacity markets for resource adequacy, would integrate smoothly with the multi-state nature of the RTO and GHG emission-reduction program.

Outside-the-Fence Models Approaches: Collateral policies

In the examples above, each state may also choose to include in its SIP other elements that contribute to the state's compliance strategy for reliably reducing GHG emissions at existing EGUs and NGCCs. The state would need to demonstrate and quantify the effect of such other SIP elements on emissions from Section 111(d) units, with a monitoring and verification protocol with back-up actions in the event that such other SIP elements do not bring forth their anticipated emissions reduction outcomes. For example:

- A state wanting to encourage the eventual shutdown of a particular utility-owned generating unit (e.g., a coal plant with high emissions CO_2 per MWh) learns from the grid operator that the plant is needed for reliability issues pending completion of transmission upgrades (or the completion of a new power plant then under construction). The utility does not want to retire the plant when those other facilities are complete, because the plant would have stranded costs. To encourage the timely retirement of the high-emitting coal plant, the state could include in its SIP a plan to allocate to the utility owner a quantity of CO_2/MWh credits for some number of years beyond the unit's actual retirement, as long as the unit were to retire by a date certain. This could allow that unit's owner offset its stranded costs by selling those emissions to others after the unit retirement occurs.

- One state wanting to gain access to underutilized NGCC capacity in a neighboring state through cost-effective transmission upgrades might enter into an interstate agreement to allocate additional credits to the neighboring state upon completion of the line. The state might propose to shut down a particular Section 111(d) unit upon the completion of the transmission-system upgrade, and free up those credits to cover the emissions in the neighboring state that will go up once the line is energized and the NGCC capacity factors increase.

- A state seeking to avoid the premature retirement of a financially challenged but well-performing existing nuclear unit(s) might propose a SIP element to create financial incentives for the unit to remain in operation through its full operating license period. For example, a state already participating in a multi-state RTO and multi-state GHG program might additionally introduce a clean energy (applicable to LSEs) or a tradable emission standard (applicable to all generating units located physically within the state). Through the CES or the TES, the nuclear unit could generate MWh without emitting any CO_2, sell those zero-carbon MWh credits to other generators in the state, capture enough monetary value for its supply of zero-carbon MWh to remain in service, and in so doing, help the entire system retain greater fuel diversity and reliability while also cost-effectively reducing system-wide CO_2/MWh.

These examples are suggestive of the types of elements that a state may include in its SIP to address local industry conditions, reliability considerations, system diversity, and economic impacts of Section 111(d) compliance. As many states have already begun to do, they can start their SIP planning processes with the expectation that they will be able to tailor their plan to suit their own preferences and policy objectives. This flexibility is inherent within Section 111(d), and affords a strong basis for allowing the states to comply with the CAA's requirements without jeopardizing electric system reliability.

Conclusions

The bottom line: as long as states and the industry start their planning process soon, there is no reasonable basis for anticipating that EPA's guidance, the states' SIPs and the electric industry's compliance with them will create reliability problems for the power system.

The nature of Section 111(d) affords the states with many options for compliance, both in terms of plan elements and timing. States will have significant flexibility in developing their GHG reduction plans, and EPA will allow them to craft their plans in ways that accommodate reliability considerations. This flexibility is a hallmark of the Section 111(d) regulatory framework, and this 'cooperative federalism' framework distinguishes it from some of the other recent air regulations that allow for a more narrow range of compliance strategies (e.g., MATS regulations affecting existing coal-fired power plants).

Moreover, the conditions in the industry are such that compliance paths may be facilitated by low natural gas prices, significant existing under-utilized NGCC capacity, relatively slow growth in demand for electricity, increased supply expected from low-carbon renewable energy, and retirements of many of the older and least efficient coal-fired power plants before the implementation dates anticipated for Section 111(d).

To a significant degree, if a state has concerns about the reliability implications of compliance with EPA's action to regulate GHG emission from existing fossil power plants, that state has a range of actions it can take today to address and mitigate these concerns. The states need not wait for EPA to propose and finalize its guidance before asking parties to propose plan elements; many states have already begun such discussions and planning. States can request transmission plans from their utilities and grid operators that examine the implications of particular plan elements on generation dispatch, emissions outlooks, and reliability issues. They can examine conditions that could cause output at Section 111(d) units to increase and to put pressure on meeting GHG emissions targets, and explore potential actions to mitigate those risks. State can step up actions to address reliability concerns now, rather than 18 months from now when the EPA finalizes its guidance.

The states are in the driver seat in navigating compliance paths under Section 111(d) that assure reliable electricity supply as well as cost-effective GHG emissions reductions from existing power plants.

APPENDIX 1:

The Clean Air Act Section 111 – Excerpts

Section 111(a)

(a) Definitions. For purposes of this section:

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

(2) The term "new source" means any stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under this section which will be applicable to such source.

(3) The term "stationary source" means any building, structure, facility, or installation which emits or may emit any air pollutant. Nothing in subchapter II of this chapter relating to nonroad engines shall be construed to apply to stationary internal combustion engines.

(4) The term "modification" means any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted.

(5) The term "owner or operator" means any person who owns, leases, operates, controls, or supervises a stationary source.

(6) The term "existing source" means any stationary source other than a new source……

Section 111(d) Standards of performance for existing sources; remaining useful life of source

(1) The Administrator shall prescribe regulations which shall establish a procedure similar to that provided by section 110 under which each State shall submit to the Administrator a plan which (A) establishes standards of performance for any existing source for any air pollutant (i) for which air quality criteria have not been issued or which is not included on a list published under section 108(a) or 112(b)(1)(A) but (ii) to which a standard of performance under this section would apply if such existing source were a new source, and (B) provides for the implementation and enforcement of such standards of performance. Regulations of the Administrator under this paragraph shall permit the State in applying a standard of performance to any particular source under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies.

(2) The Administrator shall have the same authority—

(A) to prescribe a plan for a State in cases where the State fails to submit a satisfactory plan as he would have under section 110(c) in the case of failure to submit an implementation plan, and

(B) to enforce the provisions of such plan in cases where the State fails to enforce them as he would have under sections 113 and 114 with respect to an implementation plan. In promulgating a standard of performance under a plan prescribed under this paragraph, the Administrator shall take into consideration, among other factors, remaining useful lives of the sources in the category of sources to which such standard applies.

APPENDIX 2 –

Generating Capacity Subject to 111(d) by State as of the beginning of 2013 (Page 1)

	Steam Turbine - Coal			Steam Turbine - Oil			Steam Turbine - Natural Gas			Combined Cycle - Natural Gas			Combined Cycle - Oil		
State	MW Capacity	Number of Units	Capacity Factor (2012)	MW Capacity	Number of Units	Capacity Factor (2012)	MW Capacity	Number of Units	Capacity Factor (2012)	MW Capacity	Number of Units	Capacity Factor (2012)	MW Capacity	Number of Units	Capacity Factor (2012)
ALABAMA	10,790	35	49%	453	15	49%	64	9	77%	6,255	42	63%	0	0	0%
ALASKA	118	16	67%	-	-	0%	-	-	0%	279	4	70%	47	1	77%
ARIZONA	6,230	18	75%	-	-	0%	974	9	7%	6,452	43	32%	0	0	0%
ARKANSAS	5,144	7	63%	300	11	71%	1,203	8	8%	3,060	23	38%	0	0	0%
CALIFORNIA	250	8	61%	-	-	0%	12,848	48	8%	12,830	129	51%	0	0	0%
COLORADO	5,377	26	73%	-	-	0%	120	4	1%	1,663	28	39%	0	0	0%
CONNECTICUT	388	1	3%	1,861	7	2%	44	5	23%	2,303	15	23%	0	0	0%
DELAWARE	430	3	31%	-	-	0%	846	6	15%	756	6	53%	0	0	0%
FLORIDA	10,493	29	49%	5,499	23	17%	1,038	14	22%	16,785	104	60%	0	0	0%
GEORGIA	12,583	43	38%	655	20	52%	129	2	9%	4,877	26	55%	0	0	0%
HAWAII	180	1	95%	1,119	21	46%	-	-	0%	-	-	0%	375	12	55%
IDAHO	17	6	61%	74	4	65%	-	-	0%	374	4	39%	0	0	0%
ILLINOIS	15,943	71	56%	-	-	0%	40	7	3%	2,005	14	33%	0	0	0%
INDIANA	18,283	78	58%	158	4	0%	-	-	0%	1,549	12	64%	0	0	0%
IOWA	6,784	49	60%	-	-	0%	65	2	14%	813	7	12%	0	0	0%
KANSAS	5,096	14	63%	-	-	0%	1,714	29	11%	-	-	0%	0	0	0%
KENTUCKY	15,329	54	63%	-	-	0%	-	-	0%	-	-	0%	0	0	0%
LOUISIANA	4,430	14	64%	266	7	62%	8,049	64	22%	5,916	41	54%	0	0	0%
MAINE	-	-	0%	1,222	19	20%	93	2	65%	880	5	33%	0	0	0%
MARYLAND	4,771	16	40%	1,730	4	18%	321	8	6%	157	2	31%	0	0	0%
MASSACHUSETTS	1,439	8	18%	2,138	6	1%	645	16	6%	4,315	26	34%	282	4	4%
MICHIGAN	11,778	83	53%	51	2	86%	2,182	9	4%	3,378	33	45%	0	0	0%
MINNESOTA	4,755	41	55%	15	1	50%	174	17	18%	1,502	11	29%	0	0	0%
MISSISSIPPI	2,566	7	33%	235	8	59%	2,773	23	20%	4,685	29	49%	0	0	0%
MISSOURI	12,435	51	67%	-	-	0%	116	6	1%	1,425	11	19%	0	0	0%
MONTANA	1,763	8	62%	-	-	0%	-	-	0%	41	1	0%	0	0	0%
NEBRASKA	4,160	20	69%	-	-	0%	268	9	2%	296	5	11%	0	0	0%
NEVADA	1,303	7	36%	-	-	0%	470	5	7%	3,377	34	54%	0	0	0%
NEW HAMPSHIR	554	4	26%	407	4	2%	-	-	0%	882	4	57%	0	0	0%
NEW JERSEY	2,001	7	15%	163	3	2%	629	8	3%	4,132	42	49%	0	0	0%
NEW MEXICO	3,430	7	72%	-	-	0%	779	11	32%	925	8	48%	0	0	0%
NEW YORK	1,736	15	25%	2,795	9	10%	6,927	22	17%	6,425	63	49%	0	0	0%
NORTH CAROLIN	11,084	34	50%	163	7	66%	-	-	0%	2,809	21	46%	0	0	0%
NORTH DAKOTA	4,153	14	78%	-	-	0%	-	-	0%	-	-	0%	0	0	0%
OHIO	19,394	84	49%	45	3	82%	35	2	1%	2,292	20	67%	0	0	0%
OKLAHOMA	5,323	15	63%	58	1	85%	5,085	32	19%	4,394	31	49%	0	0	0%
OREGON	585	1	52%	59	2	41%	32	2	26%	2,100	18	44%	0	0	0%
PENNSYLVANIA	14,901	59	58%	842	5	7%	1,635	4	11%	5,614	42	64%	0	0	0%
RHODE ISLAND	-	-	0%	4	2	19%	9	4	22%	1,293	11	47%	0	0	0%
SOUTH CAROLIN	6,082	22	50%	244	7	44%	107	3	47%	1,682	10	48%	0	0	0%
SOUTH DAKOTA	475	1	68%	-	-	0%	-	-	0%	170	1	1%	0	0	0%
TENNESSEE	7,734	49	52%	186	6	46%	-	-	0%	960	5	48%	0	0	0%
TEXAS	21,335	40	69%	161	6	77%	18,553	88	13%	27,324	207	50%	0	0	0%
UTAH	4,887	15	72%	-	-	0%	240	4	6%	713	5	55%	0	0	0%
VERMONT	-	-	0%	2	3	26%	-	-	0%	-	-	0%	0	0	0%
VIRGINIA	5,890	41	26%	1,899	14	11%	334	4	7%	2,779	20	78%	0	0	0%
WASHINGTON	1,340	2	32%	150	9	55%	5	1	15%	2,225	21	23%	0	0	0%
WEST VIRGINIA	14,378	33	56%	-	-	0%	-	-	0%	-	-	0%	0	0	0%
WISCONSIN	8,618	58	44%	135	8	55%	7	1	16%	1,724	12	44%	0	0	0%
WYOMING	6,431	24	77%	0	1	51%	3	3	65%	-	-	0%	0	0	0%
50 STATES	292,375	1,204		22,636	227		68,489	482		148,160	1,154		705	17	
source: SNL Financial															

APPENDIX 2 –

Generating Capacity Subject to 111(d) by State as of the beginning of 2013 (Page 2)

	All Section 111(d) Units		Nuclear			Wind and Solar			Other		Total Grid-Connected	
State	MW Capacity	Number of Units	MW Capacity	Number of Units	Capacity Factor (2012)	MW Capacity	Number of Units	Capacity Factor (2012)	MW Capacity	Number of Units	MW Capacity	Number of Units
ALABAMA	17,562	101	5,135	5	91%	0	1	0%	10,361	175	33,058	282
ALASKA	444	21	-	-	0%	33	25	7%	1,766	473	2,243	519
ARIZONA	13,656	70	3,937	3	93%	829	65	16%	9,634	133	28,056	271
ARKANSAS	9,707	49	1,865	2	95%	-	-	0%	4,300	112	15,872	163
CALIFORNIA	25,929	185	2,240	2	90%	6,202	498	19%	33,424	1,431	67,795	2,116
COLORADO	7,161	58	-	-	0%	2,411	61	29%	5,685	228	15,256	347
CONNECTICUT	4,596	28	2,117	2	92%	1	6	0%	2,687	144	9,401	180
DELAWARE	2,032	15	-	-	0%	15	4	20%	1,001	31	3,048	50
FLORIDA	33,815	170	3,140	4	65%	74	11	16%	23,441	401	60,470	586
GEORGIA	18,244	91	4,061	4	95%	3	3	5%	17,498	350	39,806	448
HAWAII	1,674	34	-	-	0%	185	27	20%	813	110	2,672	171
IDAHA	465	14	-	-	0%	973	32	22%	3,725	203	5,162	249
ILLINOIS	17,988	92	11,673	11	94%	3,579	36	25%	14,462	577	47,703	716
INDIANA	19,991	94	-	-	0%	1,543	15	24%	6,300	217	27,834	326
IOWA	7,663	58	622	1	80%	5,050	77	32%	3,134	499	16,469	635
KANSAS	6,810	43	1,205	1	78%	2,516	19	22%	3,504	403	14,034	466
KENTUCKY	15,329	54	-	-	0%	-	-	0%	6,768	111	22,098	165
LOUISIANA	18,660	126	2,157	2	83%	-	-	0%	5,551	134	26,368	262
MAINE	2,195	26	-	-	0%	411	10	23%	2,057	292	4,663	328
MARYLAND	6,979	30	1,734	2	89%	148	14	26%	3,819	156	12,680	202
MASSACHUSETTS	8,820	60	685	1	98%	93	32	11%	5,171	231	14,769	324
MICHIGAN	17,389	127	4,131	4	77%	820	16	15%	9,412	644	31,753	791
MINNESOTA	6,445	70	1,697	3	80%	2,867	145	30%	5,333	433	16,342	651
MISSISSIPPI	10,260	67	1,265	1	66%	-	-	0%	4,532	71	16,056	139
MISSOURI	13,977	68	1,240	1	99%	459	6	31%	7,185	377	22,860	452
MONTANA	1,803	9	-	-	0%	638	10	26%	3,150	95	5,591	114
NEBRASKA	4,725	34	1,271	2	52%	415	11	34%	2,032	253	8,443	300
NEVADA	5,150	46	-	-	0%	411	18	12%	5,486	135	11,046	199
NEW HAMPSHIR	1,843	12	1,247	1	75%	171	3	14%	1,311	142	4,571	158
NEW JERSEY	6,924	60	4,273	4	88%	285	128	11%	8,889	233	20,371	425
NEW MEXICO	5,134	26	-	-	0%	921	34	31%	1,833	67	7,887	127
NEW YORK	17,883	109	5,286	6	88%	1,598	27	20%	15,171	843	39,937	985
NORTH CAROLIN	14,056	62	5,206	5	86%	153	64	8%	11,321	344	30,736	475
NORTH DAKOTA	4,153	14	-	-	0%	1,805	28	34%	626	40	6,585	82
OHIO	21,765	109	2,176	2	90%	484	13	24%	9,588	332	34,012	456
OKLAHOMA	14,860	79	-	-	0%	2,973	27	31%	5,494	129	23,326	235
OREGON	2,776	23	-	-	0%	3,154	60	22%	8,144	256	14,074	339
PENNSYLVANIA	22,992	110	9,896	9	87%	1,377	43	18%	9,967	375	44,232	537
RHODE ISLAND	1,306	17	-	-	0%	2	1	0%	712	35	2,019	53
SOUTH CAROLIN	8,115	42	6,659	7	88%	0	1	0%	9,158	254	23,931	304
SOUTH DAKOTA	645	2	-	-	0%	767	11	42%	2,825	75	4,237	88
TENNESSEE	8,879	60	3,512	3	82%	44	5	12%	8,077	190	20,512	258
TEXAS	67,373	341	5,020	4	87%	11,700	116	31%	22,492	504	106,585	965
UTAH	5,840	24	-	-	0%	19	1	24%	1,550	143	7,408	168
VERMONT	2	3	628	1	91%	133	11	9%	545	139	1,308	154
VIRGINIA	10,902	79	3,637	4	90%	-	-	0%	11,750	626	26,288	709
WASHINGTON	3,719	33	1,158	1	92%	2,802	24	27%	24,743	379	32,422	437
WEST VIRGINIA	14,378	33	-	-	0%	583	6	25%	1,542	50	16,503	89
WISCONSIN	10,485	79	1,209	2	92%	614	12	28%	6,252	534	18,559	627
WYOMING	6,434	28	-	-	0%	1,383	30	35%	586	58	8,404	116
50 STATES	532,364	3,084	94,944	95		60,642	1,786		354,445	13,992	1,042,395	18,957

source: SNL Financial

APPENDIX 3 –

MAP of NERC REGIONS AND SUBREGIONS