



December 1, 2014

U.S. Environmental Protection Agency
 Attention Docket ID No. EPA-HQ-OAR-2013-0602
 EPA Docket Center, U.S. EPA, Mailcode: 28221T
 1200 Pennsylvania Avenue, NW
 Washington, DC 20460

Re: Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generation Units, Proposed Rule, Docket ID No. EPA-HQ-OAR-2013-0602; FRL-9910-86-OAR, 79 Fed. Reg. 34,830 (June 18, 2014)

Dear Sir or Madam:

The American Chemistry Council, American Forest & Paper Association, American Fuel & Petrochemical Manufacturers, American Iron and Steel Institute, American Petroleum Institute, American Wood Council, Brick Industry Association, Corn Refiners Association, Council of Industrial Boiler Owners, Electricity Consumers Resource Council, National Association of Home Builders, the National Association of Manufacturers, National Lime Association, National Oilseed Processors Association, Portland Cement Association, The Fertilizer Institute, and the U.S. Chamber of Commerce, (collectively, “the Associations”) appreciate the opportunity to submit the following comments in response to the Environmental Protection Agency’s (“EPA’s”) proposed Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generation Units, Docket ID No. EPA-HQ-OAR-2013-0602; FRL-9910-86-OAR, 79 Fed. Reg. 34,830 (June 18, 2014) (hereinafter, the “proposed rule” or “proposed ESPS”).

The **American Chemistry Council** (“ACC”) represents the leading companies engaged in the business of chemistry. ACC members apply the science of chemistry to make innovative products and services that make people's lives better, healthier and safer. ACC is committed to improved environmental, health and safety performance through Responsible Care®, common sense advocacy designed to address major public policy issues, and health and environmental research and product testing. The business of chemistry is a \$812 billion enterprise and a key element of the nation's economy.

The **American Forest & Paper Association** (“AF&PA”) is the national trade association of the paper and wood products industry, which accounts for approximately 4 percent of the total U.S. manufacturing GDP. The industry makes products essential for everyday life from renewable and recyclable resources, producing about \$210 billion in products annually and employing nearly 900,000 men and women with an annual payroll of approximately \$50 billion.

The **American Fuel & Petrochemical Manufacturers** (“AFPM”) (formerly known as NPRA, the National Petrochemical & Refiners Association) is a national trade association whose members comprise more than 400 companies, including virtually all United States refiners and petrochemical manufacturers. AFPM’s members supply consumers with a wide variety of products and services that are used daily in homes and businesses.

The **American Iron and Steel Institute** (“AISI”) serves as the voice of the North American steel industry in the public policy arena and advances the case for steel in the marketplace as the preferred material of choice. AISI also plays a lead role in the development and application of new steels and steelmaking technology. AISI is comprised of 20 member companies, including integrated and electric furnace steelmakers, and approximately 125 associate members who are suppliers to or customers of the steel industry. AISI’s member companies represent more than three quarters of both U.S. and North American steel capacity.

The **American Petroleum Institute** (“API”) represents over 590 oil and natural gas companies, leaders of a technology-driven industry that supplies most of America's energy, supports more than 9.8 million jobs and 8 percent of the U.S. economy, and, since 2000, has invested nearly \$2 trillion in U.S. capital projects to advance all forms of energy, including alternatives.

The **American Wood Council** (“AWC”) is the voice of North American traditional and engineered wood products, representing over 75% of the industry. From a renewable resource that absorbs and sequesters carbon, the wood products industry makes products that are essential to everyday life and employs more than 360,000 men and women in family-wage jobs.

The **Brick Industry Association** (“BIA”), founded in 1934, is the recognized national authority on clay brick manufacturing and construction, representing approximately 250 manufacturers, distributors, and suppliers that historically provide jobs for 200,000 Americans in 45 states.

The **Corn Refiners Association** (“CRA”) is the national trade association representing the corn refining (wet milling) industry of the United States. CRA and its predecessors have served this important segment of American agribusiness since 1913. Corn refiners manufacture

sweeteners, ethanol, starch, bioproducts, corn oil and feed products from corn components such as starch, oil, protein and fiber.

The **Council of Industrial Boiler Owners** (“CIBO”) is a trade association of industrial boiler owners, architect-engineers, related equipment manufacturers, and University affiliates representing 20 major industrial sectors. CIBO members have facilities in every region of the country and a representative distribution of almost every type of boiler and fuel combination currently in operation. CIBO was formed in 1978 to promote the exchange of information about issues affecting industrial boilers, including energy and environmental equipment, technology, operations, policies, laws and regulations.

The **Electricity Consumers Resource Council** (“ELCON”) is the national association representing large industrial consumers of electricity. ELCON member companies produce a wide range of industrial commodities and consumer goods from virtually every segment of the manufacturing community. ELCON members operate hundreds of major facilities in all regions of the United States. Many ELCON members also cogenerate electricity as a by-product to serving a manufacturing steam requirement.

The **National Association of Home Builders** (“NAHB”) is a federation of more than 850 state and local home builder associations nationwide. The organization’s membership includes over 140,000 firms engaged in land development, single and multifamily construction, remodeling, multifamily ownership, building material trades, and commercial and light industrial construction projects. Over 80 percent of NAHB’s members are classified as “small businesses,” as defined by the U.S. Small Business Administration, and NAHB members collectively employ over 3.4 million people nationwide. Four out of every five new homes are built by NAHB members.

The **National Association of Manufacturers** (“NAM”) is the largest manufacturing association in the United States, representing small and large manufacturers in every industrial sector and in all 50 states. Manufacturing employs nearly 12 million men and women, contributes more than \$1.8 trillion to the U.S. economy annually, has the largest economic impact of any major sector and accounts for two-thirds of private-sector research and development. The NAM is the powerful voice of the manufacturing community and the leading advocate for a policy agenda that helps manufacturers compete in the global economy and create jobs across the United States.

The **National Lime Association** (“NLA”) is the industry trade association for the manufacturers of high calcium quicklime and dolomitic quicklime (calcium oxide) and hydrated lime (calcium hydroxide), which are collectively and commonly referred to as “lime.” Lime is used in a wide array of critical applications and industries, including for environmental control and protection, metallurgical, construction, chemical and food production. With plant operations located in 24 states, NLA’s members produce greater than 99 percent of the United States’ calcium oxides and hydroxides.

The **National Oilseed Processors Association** (“NOPA”) is a national trade association that represents 13 companies engaged in the production of vegetable meals and vegetable oils from oilseeds, including soybeans. NOPA’s member companies process more than 1.6 billion

bushels of oilseeds annually at 63 plants in 19 states, including 57 plants which process soybeans.

The **Portland Cement Association** (“PCA”) represents 27 U.S. cement companies operating 82 manufacturing plants in 35 states, with distribution centers in all 50 states, servicing nearly every Congressional district. PCA members account for approximately 80% of domestic cement-making capacity

The **Fertilizer Institute** (“TFI”) represents the nation’s fertilizer industry including producers, importers, retailers, wholesalers and companies that provide services to the fertilizer industry. TFI’s members provide nutrients that nourish the nation’s crops, helping to ensure a stable and reliable food supply.

The **U.S. Chamber of Commerce** (the “Chamber”) is the world’s largest business federation representing the interests of more than 3 million businesses of all sizes, sectors, and regions, as well as state and local chambers and industry associations. The Chamber is dedicated to promoting, protecting, and defending America’s free enterprise system.

INTRODUCTION

The Associations represent the nation’s leading energy, agriculture, and manufacturing sectors that form the backbone of the nation’s industrial ability to grow our economy and provide jobs in an environmentally-sustainable and energy-efficient manner. Significantly, the Associations both represent, and are reliant upon, electric utilities, which will be directly regulated and impacted by the EPA’s proposed ESPS governing carbon emissions. EPA, in the proposed ESPS, asserts unprecedented jurisdiction over electricity production and dispatch, as well as retail demand for electricity by the Associations’ member companies. The Associations are key and necessary stakeholders regarding any regulation that impacts energy and which may impact manufacturers directly or indirectly in the future. For the reasons described below, we believe the proposed rule far exceeds the authority delegated to EPA by Congress and would have profoundly adverse consequences on both industry and the economy. We therefore urge EPA to withdraw the proposed rule and to engage instead in a process with all interested stakeholders regarding the development of a lawful and reasonable rule that will allow U.S. companies to remain competitive in the global marketplace.

EPA is proposing this rulemaking as a key component of the President’s Climate Action Plan, which identifies a wide range of actions that the administration is implementing to address the challenges of climate change. In proposing to achieve greenhouse gas (“GHG”) emission reductions from existing electricity generating units (“EGUs”) in the proposed ESPS, however, EPA for the first time in the more than 40 year history of the Clean Air Act (“CAA”) is bootstrapping unprecedented, newfound legal powers onto its existing legal authority without the necessary legislative amendment. This self-enacted authorization would elevate the Agency to the most influential and pervasive federal regulator of not just the environment, but the generation, distribution, and utilization of electricity in the nation. Such a role reaches far

beyond the bounds of the CAA, and the very mission of EPA as an agency established to reduce air pollution and not as a regulator of the nation's electricity grid.

At its core, the proposed ESPS is built upon a fundamental, novel, and flawed legal assumption that the CAA authorizes EPA to hold a single regulated entity liable for the actions and inactions of unrelated third parties operating at other facilities, other energy sectors, and even other industrial sectors. In turn, EPA indicates that those third parties similarly can be held liable by States in a legally enforceable manner to account for GHG reductions sought by the fossil fuel-fired EGU sector. As described below, neither Congress nor the courts have authorized such an expansive interpretation of the Clean Air Act that would enable EPA to implement a *de facto*, economy-wide federal regulation of the entire electricity sector in the United States.

Indeed, in critical respects, EPA is effectively commanding the States both as to how they must generate and dispatch electricity as well as how they must regulate demand for electricity. Despite EPA's references to flexibility, in practice, the emission reduction targets EPA has proposed can only be met if States mandate construction of EPA's preferred sources of electricity and then abandon current use of economic dispatch priorities in favor of EPA's preferred dispatch order, without regard to the costs to the States, utilities, and consumers. To meet EPA's emissions targets, States will also need to implement renewable energy policies at EPA's direction and mandate aggressive retail demand reduction programs. In many instances, these changes would require a State to enact a host of new laws because existing laws do not permit the types of regulatory actions desired by EPA, thereby dictating federal energy policies on inherently State-centric issues. Nowhere in the Clean Air Act did Congress provide EPA with the authority to commandeer State police powers in this way—nor could it, as such mandates violate the Tenth Amendment. Indeed, the Federal Power Act (“FPA”) delicately divides authority over the electricity sector between States on the one hand and the Federal Energy Regulatory Commission (“FERC”) on the other, leaving no space for EPA to regulate.

The Associations strongly oppose EPA's approach in the proposed ESPS both because of the irreparable harm it will cause to electricity generation, reliability, and costs—if not to the economy as a whole—and because of the extraordinary precedent that EPA is proposing to create. Departing from the established approaches to Section 111(d) the Agency has taken for scores of years, EPA cannot bootstrap its own authority for the first time to read away the entire premise on which the Clean Air Act is based—that regulated entities are accountable for actions specifically at their facilities and their facilities only, and cannot be held liable for unrelated actions and actors beyond the fence line of those facilities and in sectors that are not even subject to the rule at issue. Nor can EPA commandeer State regulatory authority over local electricity markets—EPA has no authority to regulate electricity generation, dispatch and demand and EPA cannot force States to restructure their electricity markets to suit EPA's preferences.

If EPA proceeds to finalize the ESPS in this form, it will be ushering in a new regulatory era where it will be able to regulate any entity in full disregard for the specific facility and technology-based limits that are the touchstone of Section 111's approach to regulation of stationary sources. Like any other rulemaking, in the proposed ESPS, EPA must work within the bounds of the tools that exist and not effectively amend its own authority in new ways that Congress has not authorized. As the Supreme Court recently reminded EPA, “[w]hen an agency

claims to discover in a long-extant statute an unheralded power to regulate ‘a significant portion of the American economy’ ... we typically greet its announcement with a measure of skepticism.” *Utility Air Regulatory Group v. EPA*, 134 S. Ct. 2427, 2444 (2014) (“*UARG*”) (quoting *FDA v. Brown & Williamson Tobacco Corp.*, 529 U.S. 120, 159 (2000)).

The Associations’ specific comments are summarized below:

- The proposed rule exceeds EPA’s authority because Congress did not intend EPA to use Section 111(d) as a means to exercise regulatory control over the entire electricity sector.
- The proposed rule should be withdrawn because it is harming the Associations’ members. EPA’s proposed compliance schedules are unreasonably short and, at a minimum, EPA must eliminate the interim emission reduction targets to allow States to reduce emissions over a reasonable time period. To meet EPA’s aggressive 2020 emission reduction targets, utilities and the States must take immediate action to implement heat rate improvements and construct new energy infrastructure. The Associations’ manufacturing members will be harmed through higher electricity prices, the risk of power outages, and competition for raw materials such as natural gas.
- EPA is not authorized to expand regulation of fossil fuel-fired EGUs under Section 111 to include existing sources under Section 111(d) because EGUs are already subject to regulation under Section 112.
- EPA cannot regulate a source category under Section 111 until it has first made a source- and pollutant-specific endangerment determination and significance finding, which it has not done here.
- EPA’s regulation of existing sources under Section 111(d) is inextricably tied to its regulation of new sources under Section 111(b), and EPA unlawfully deviates from the proposed standards of performance for new sources in this proposed rule.
- EPA cannot establish binding emission rate targets because the plain language of the Clean Air Act directs the States—not EPA—to establish standards of performance. Further, the emission reduction targets proposed by EPA are contrary to the FPA and the Tenth Amendment.
- EPA’s proposed emission reduction targets are unlawful because they are not based on an adequately demonstrated best system of emission reduction (“BSER”) for fossil fuel-fired EGUs. The plain language of Section 111, EPA’s past practice, and the structure of the Clean Air Act as a whole all confirm that EPA cannot look beyond the fence line when conducting a BSER analysis. Further, to the extent that there is any ambiguity in Section 111(d), which the Associations dispute, EPA cannot use that ambiguity to regulate and restructure the entire electricity sector.

- EPA’s proposed emission reduction targets are arbitrary and capricious because EPA fails to consider key issues that call into question the aggressive emission reductions EPA proposes for each of the four Building Blocks.
- EPA may not use Section 111(d) to impose binding legal obligations on entities that are not part of the source category subject to regulation.
- EPA may not base its BSER analysis and emissions rate reduction targets on beyond the fence line emission reductions that EPA lacks authority to implement as part of a federal implementation plan.
- EPA may not simultaneously regulate modified and reconstructed sources as new sources subject to Section 111(b) and as existing sources under Section 111(d) because those categories are defined in a mutually exclusive manner in Section 111.
- EPA’s proposal to regulate simple cycle turbines in the same manner as combined cycle turbines is arbitrary and capricious due to the fundamentally different role that simple cycle turbines play within the United States’ energy portfolio.
- EPA’s proposal to include industrial combined heat and power (“CHP”) units is arbitrary and capricious and fails to fully account for the environmental benefits that CHP offers. EPA must modify the applicability criteria to exclude industrial CHP units.
- EPA’s assessment of the costs and benefits of the proposed rule are arbitrary and capricious because EPA relies on a defective Social Cost of Carbon (“SCC”) document that, among other flaws, relies on international harms associated with GHG emissions without complying with the proper procedures under Section 115 or evaluating the potential for international leakage of CO₂ emissions. In addition, EPA fails to conduct whole economy modeling, and inappropriately considers benefits associated with the reduction of non-GHG pollutants. Further, before finalizing the proposed rule, EPA must convene a Small Business Advocacy Review panel to evaluate how the proposed rule will affect small businesses.
- To promote flexibility, EPA should allow EGUs to incorporate voluntary emission reductions implemented by third parties as part of a compliance program.
- By prohibiting States from incorporating existing GHG reduction programs into their implementation plans, EPA is inappropriately constraining the States’ flexibility to implement plans to reduce CO₂ emissions from the electricity sector.
- EPA’s applicability criteria for offsets in State implementation plans unfairly penalize States and affected EGUs that have taken early action to reduce GHG emissions.
- EPA must ensure that any sources that may be subject to binding obligations under a portfolio approach are exempted from any future Section 111 standards of performance that may be issued for other source categories.

- Before finalizing the rule, EPA must develop and permit public comment on rules for measuring and verifying emission reductions associated with renewable energy and energy efficiency programs.
- Before finalizing the proposed rule, EPA must provide additional, detailed guidance to the States regarding the conversion of rate-based emission reduction targets into mass-based standards.
- EPA has appropriately included multi-year compliance periods that provide some relief from unforeseen circumstances that could increase emissions in a given compliance year.
- EPA appropriately concluded that carbon capture and sequestration is not BSER for existing coal-fired EGUs.
- EPA has violated Section 307(b) by failing to include in the rulemaking docket key data on which it relies in setting the State emission reduction targets.
- EPA must base the final rule on representative baseline data by considering data from additional years besides 2012.
- EPA's reliance on projects receiving federal funding under the Energy Policy Act of 2005 is arbitrary, capricious, and unlawful.
- EPA must impose the same applicability criteria for existing sources under Section 111(d) that it imposes for newly constructed sources in the same source category under Section 111(b).
- EPA cannot rely on untimely notices of data availability and other technical support documents to cure defects in its original proposal.
- EPA must not expand the Section 111 GHG regulations to any other source category.

Comments of the American Chemistry Council, American Forest & Paper Association, American Fuel & Petrochemical Manufacturers, American Iron and Steel Institute, American Petroleum Institute, American Wood Council, Brick Industry Association, Corn Refiners Association, Council of Industrial Boiler Owners, Electricity Consumers Resource Council, National Association of Home Builders, the National Association of Manufacturers, National Lime Association, National Oilseed Processors Association, Portland Cement Association, The Fertilizer Institute, and the U.S. Chamber of Commerce

On

Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generation Units, Proposed Rule, Docket ID No. EPA–HQ–OAR–2013–0602; FRL–9910–86-OAR, 79 Fed. Reg. 34,830 (June 18, 2014)

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The American Chemistry Council, American Forest & Paper Association, American Fuel & Petrochemical Manufacturers, American Iron and Steel Institute, American Petroleum Institute, American Wood Council, Brick Industry Association, Corn Refiners Association, Council of Industrial Boiler Owners, Electricity Consumers Resource Council, National Association of Home Builders, the National Association of Manufacturers, National Lime Association, National Oilseed Processors Association, Portland Cement Association, The Fertilizer Institute, and the U.S. Chamber of Commerce (collectively “the Associations”) hereby submit the following comments on the Environmental Protection Agency’s (“EPA’s”) proposed Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generation Units, Docket ID No. EPA–HQ–OAR–2013–0602; FRL–9910–86–OAR, 79 Fed. Reg. 34,830 (June 18, 2014) (hereinafter, the “proposed rule” or “proposed ESPS”).

I. THE PROPOSED RULE EXCEEDS EPA’S AUTHORITY UNDER THE CLEAN AIR ACT BECAUSE CONGRESS DID NOT INTEND SECTION 111(d) TO PROVIDE EXPANSIVE AUTHORIZATION TO EPA TO REGULATE THE ELECTRICITY SECTOR

The proposed rule is unlawful because Congress did not delegate to EPA the authority to regulate and restructure the entirety of the electricity sector. In sharp contrast to prior Section 111(d) rules, EPA goes far beyond identifying pollution control techniques for fossil fuel-fired EGUs and instead seeks to reduce CO₂ emissions by restructuring virtually the entire electricity regulatory sector. In doing so, EPA proposes mandatory emission reduction targets that can only be achieved by fundamentally restructuring the way that States regulate the generation and dispatch of electricity and by changing consumer choices and behaviors, as well as potentially controlling the electricity use of industrial and commercial sectors. With good reason, courts are skeptical of agency interpretations that purport to give the agency expansive authority over significant portions of the economy, particularly when agencies encroach on subjects traditionally governed by the States. Such skepticism is warranted here, as there is no clear congressional intent in Section 111(d) for EPA to become the country’s preeminent regulator of the electricity sector.

As the Supreme Court recently reminded EPA, “[w]hen an agency claims to discover in a long-extant statute an unheralded power to regulate ‘a significant portion of the American economy’ ... we typically greet its announcement with a measure of skepticism.” *Utility Air Regulatory Group v. EPA*, 134 S. Ct. 2427, 2444 (2014) (“*UARG*”) (quoting *FDA v. Brown & Williamson Tobacco Corp.*, 529 U.S. 120, 159 (2000)). For example, when OSHA claimed authority to issue any workplace standard that was “reasonably calculated to produce a safer and more healthy work environment,” the court concluded that “[i]n the absence of a clear mandate in the Act, it is unreasonable to assume that Congress intended to give the Secretary ... unprecedented power over American industry.” *Indus. Union Dep’t, AFL-CIO v. Am. Petroleum Inst.*, 448 U.S. 607, 645 (1980). Thus, agencies cannot impose regulations of “vast ‘economic and political significance’” unless Congress has spoken clearly. *UARG*, 134 S. Ct. at 2444 (quoting *Brown & Williamson*, 529 U.S. at 160).

Congressional clarity is particularly important when a federal agency seeks to exercise authority traditionally reserved to the States. See *Will v. Michigan Dep’t of State Police*, 491 U.S. 58, 65 (1989) (“[I]f Congress intends to alter the ‘usual constitutional balance between the

States and the Federal Government,’ it must make its intention to do so ‘unmistakably clear in the language of the statute.’” (quoting *Atascadero State Hosp. v. Scanlon*, 473 U.S. 234, 242 (1985)); see also *Bond v. U.S.*, 134 S. Ct. 2077, 2089 (2014); *Gregory v. Ashcroft*, 501 U.S. 452, 460-61 (1991). In the absence of such clarity, courts “refer to basic principles of federalism embodied in the Constitution to resolve ambiguity in a federal statute.” *Bond*, 134 S. Ct. at 2090. Thus, federal agencies bear a heavy burden when they seek to displace traditional State regulatory authority. See, e.g., *Am. Bar Ass’n v. FTC*, 430 F.3d 457,472 (D.C. Cir. 2005). EPA fails to meet that burden here.

Despite being available to EPA for more than forty years, Section 111(d) remains one of the least utilized provisions in the Clean Air Act (“CAA”). In fact, prior to this rulemaking, EPA has only regulated “four pollutants from five source categories” under Section 111(d). See 79 Fed. Reg. at 34,879. And only one of those regulations was issued in the past twenty years. See 61 Fed. Reg. 9905 (Mar. 17, 1996) (establishing emissions guidelines for municipal solid waste landfills). More importantly, the scope of EPA’s regulations has been modest, focusing on pollution control technology that could be retrofitted for existing facilities and, in most cases, establishing less stringent requirements than the Section 111(b) standards of performance applicable to new sources in the same source category. Thus, neither the content of prior Section 111(d) rules nor their sheer quantity could be described as significant from a nationwide economic perspective.

The proposed rule, however, marks a dramatic shift from this past practice, and would fundamentally transform Section 111(d) to authorize what may be the single most far-reaching regulation in the history of the Agency. First, looking beyond pollution control technologies that can be retrofitted for existing fossil fuel-fired EGUs, EPA abandoned its prior source-specific approach and expanded its focus to the entire “integrated electricity system,” 79 Fed. Reg. at 34,836, including electricity generation, transmission, and, ultimately, consumption. In doing so, EPA largely eschews opportunities to reduce CO₂ emissions at existing coal-fired EGUs and instead seeks opportunities to eliminate coal-fired electricity generation. If the proposed rule were finalized, EPA essentially would shift the regulatory focus from affected EGUs to the States by commandeering their traditional authority to regulate the generation, dispatch, and transmission of electricity. Thus, unless they can find other options for emission reductions not incorporated into EPA’s BSER analysis, States would be obligated to reduce the dispatch of coal-fired electricity. EPA’s BSER analysis also assumes that States can dramatically increase renewable energy generation and implement demand-side energy efficiency programs to reduce usage rates of coal-fired EGUs. Thus, the proposed rule would prioritize the dispatch of certain preferred energy sources, regardless of the cost to consumers or impacts on reliability.

By asserting authority to regulate the entire integrated electricity system “from plant to plug,”¹ EPA goes even further than it did in *UARG*, where the Agency sought to expand the scope of the Prevention of Significant Deterioration (“PSD”) program to include “small entities such as office buildings, retail establishments, hotels ... schools, prisons, and private hospitals.”

¹ EPA, News Release, Remarks for Administrator McCarthy, Announcement of Clean Power Plan, Washington DC (June 2, 2014), available at <http://yosemite.epa.gov/opa/admpress.nsf/0/0A8E7164BB15185985257CEB0050C967>.

UARG, 134 S. Ct. at 2437 n.2 (internal quotation and citation omitted). In rejecting EPA’s interpretation of the Clean Air Act’s PSD and Title V provisions, the Court explained that “[t]he power to require permits for the construction and modification of tens of thousands, and the operation of millions of small sources nationwide falls comfortably within the class of authorizations that we have been reluctant to read into ambiguous statutory text. “ *Id.* at 2444. The breadth of EPA’s proposal here exceeds the rule at issue in *UARG*. EPA is not simply asserting authority over sources that emit CO₂ or even those that generate power. By incorporating demand-side energy efficiency, EPA is expanding the scope of Section 111(d) to include mandating the choices and behaviors of all consumers of electricity. *Cf. id.* at 2447-48 (expressing doubt that “energy efficiency” is appropriately regulated under the PSD program and emphasizing EPA’s concessions that best available control technology (“BACT”) requirements must be focused on the “proposed facility” and not “reductions in a facility’s demand for energy from the electric grid”). There is no reason to suggest that Congress intended a source-category based regulatory scheme to be applied in such an expansive manner.

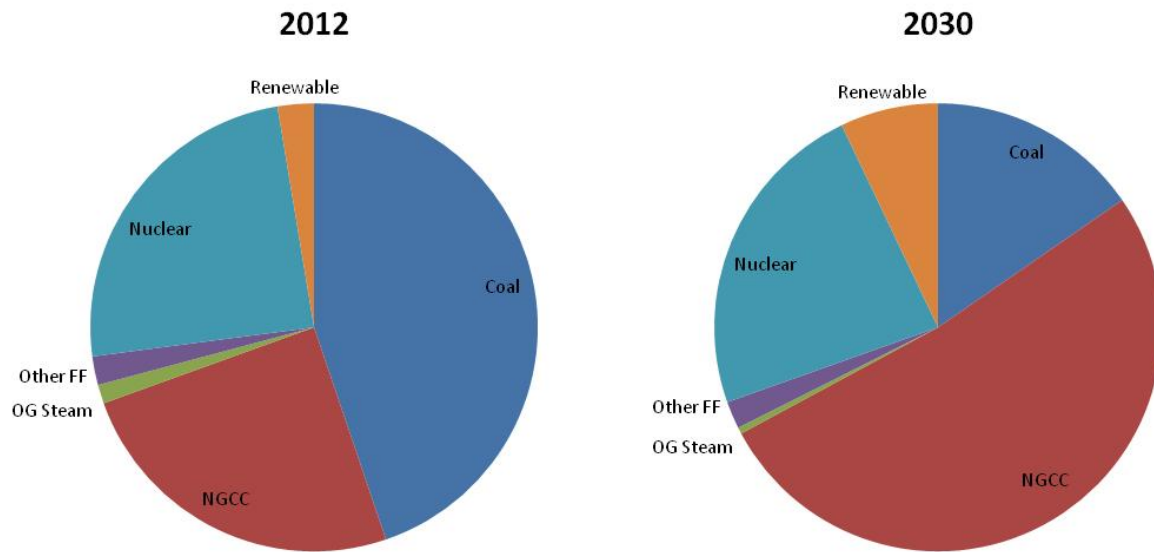
By proposing a system-wide approach to regulating CO₂ emissions from the electricity sector, EPA is largely abandoning its long-standing role as an environmental regulator focused on reducing emission of pollutants from industrial processes and instead seeks to establish itself as the primary regulator of electricity production and distribution in the United States. Indeed, under EPA’s proposal, Section 111(d) of the CAA would, in essence, dictate which energy sources could operate in a given State and even how much electricity consumers could use. Under EPA’s approach, two States with identical utilization of fossil fuel generation across a river from each other could face dramatically different regulatory regimes for their entire energy infrastructure. This unprecedented assertion of authority is unlawful. Rather than identifying a clear mandate from Congress, EPA relies on alleged ambiguity in the word “system” to transform Section 111(d) from a program under which *States* are directed to establish standards of performance *for any existing source* in a regulated source category, 42 U.S.C. § 7411(d), to one in which *EPA* purports to establish binding standards on the entire electricity sector.

EPA’s assertion of authority over the entire electricity sector is all the more troubling given the central role that States have traditionally played in regulating electricity. While the Federal Energy Regulatory Commission (“FERC”) exercises federal authority over wholesale electricity transmission, States exercise virtually exclusive authority to regulate electricity generation, local distribution, and consumption within their borders. Thus, for example, States have authority to determine whether electricity will be produced and distributed at retail by vertically integrated companies or whether it will be dispatched in a competitive market based on least-cost bidding.² States also have authority to determine whether certain sources, such as municipal power plants and cooperatives, may be subject to different regulatory obligations and dispatching requirements. States can also determine the degree to which renewable energy will be promoted through the use of incentive programs and legal mandates such as renewable portfolio standards (“RPSs”). Finally, States are primarily responsible for managing retail electricity consumption and have the discretion to determine whether and how to promote energy

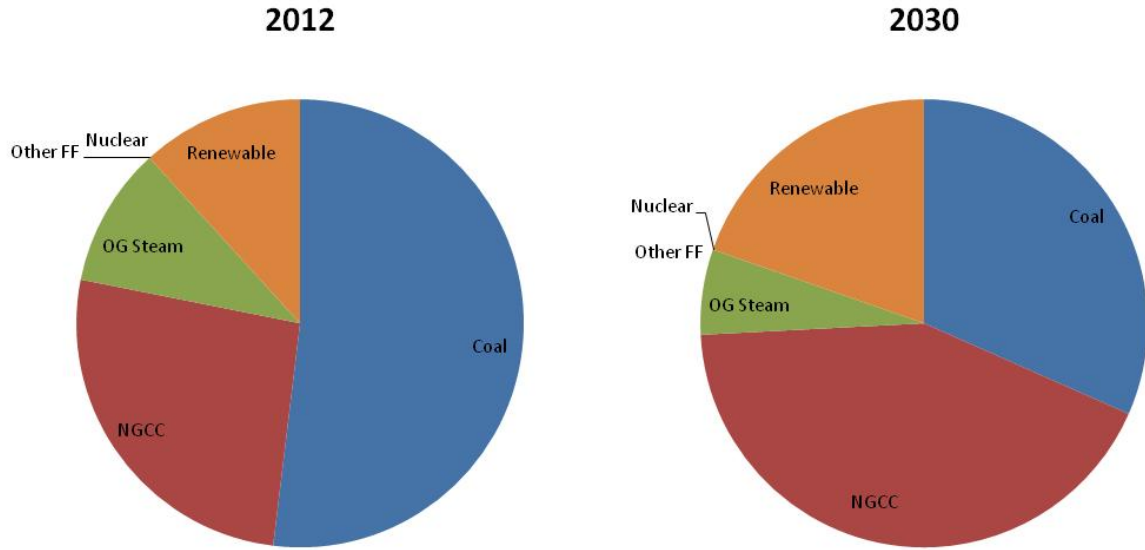
² To the extent that electricity is dispatched on an interstate basis through Regional Transmission Organizations (“RTOs”), changes to dispatching priorities are also subject to FERC approval. *See* 16 U.S.C. §§ 824d, 824e.

efficiency by retail consumers. Typically, these decisions are a combination of inherently political decisions exercised by the State legislatures and pragmatic decisions influenced by State regulators who are the experts in understanding the resources and energy infrastructure of their States. The proposal however would usurp entirely this inherently local decision making in exchange for EPA-assigned electricity budgets for a variety of sources by 2030. To illustrate the impacts of the rule on States, the following charts compare the percentage of power by type for three States as of 2012 and the mix that EPA assumes will be used to meet its emission reductions targets by 2030:

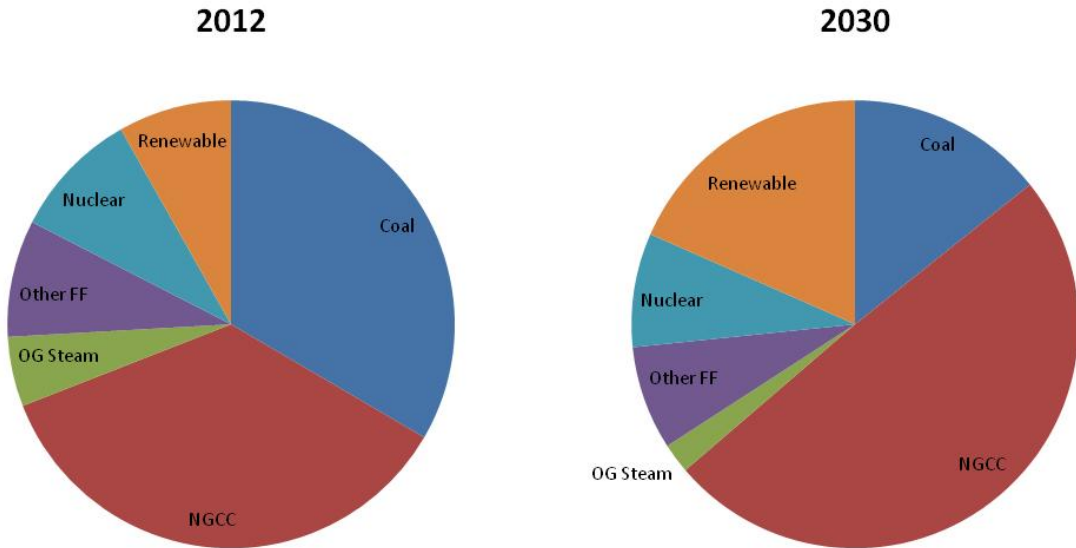
Arkansas



New Mexico



Texas



As explained in greater detail below, these changes are driven by EPA’s assumptions of how States should restructure their electricity markets to achieve the emission reduction targets the Agency is setting. As shown in the illustrative examples, EPA is assuming States should—and are able to—substantially scale back coal-fired generation and substantially increase natural gas combined cycle (“NGCC”) generation. EPA also sets its targets based on the assumption that renewable energy can be substantially increased in these States. As these charts show, States with existing nuclear capacity are assumed to maintain that capacity. This restructuring is

not based on existing State plans or on lowest cost dispatching, but instead based on how EPA believes States can reduce carbon emissions.

As such, the binding emission reduction targets proposed by EPA commandeer virtually all of this State authority by imposing aggressive schedules for renewable energy and energy efficiency, and then by mandating that States direct their utilities to make planning and operational decisions based on a least-CO₂ emission basis rather than a least-cost basis or any other metric chosen by a State. Not only is this profoundly unwise as a matter of policy, it is precluded by the Constitution: under the Tenth Amendment EPA has no authority to “compel the States to enact or administer a federal regulatory program.” *New York v. United States*, 505 U.S. 144, 188 (1992).

Furthermore, even viewed for what it is—a regulation of electricity consumption—the proposal ignores the existing delicate and sophisticated energy regulatory regimes with which it is in full tension. If implemented, EPA’s proposal is likely to threaten the very viability of providing reliable energy across the grid. Even without any additional regulatory changes, electricity grids are currently being operated with very little margin for error. At a recent Senate Hearing, FERC Commissioner Philip D. Moeller explained that “the experience of this past winter indicates that the power grid is now already at the limit.”³ Likewise, the Government Accountability Office recently noted that existing EPA regulations, including the Mercury & Air Toxics Standards (“MATS”), Cross State Air Pollution Rule (“CSAPR”), and the Clean Water Act Section 316 Cooling Water Intake Structures rule “may contribute to reliability challenges in some regions.”⁴

EPA fails to appreciate the fragility of the electricity transmission system and the effect that the proposed rule would have on grid reliability over time. EPA’s failure to fully and properly assess and account for the proposal’s impact on grid reliability puts at risk the economic viability of thousands of manufacturing facilities in the United States that are interconnected to their utilities at transmission voltages. The Associations’ members are well aware of the harm posed by power outages. The direct economic damage of the August 2003 Blackout, which was limited to parts of just seven States was estimated as high as \$10 billion.⁵ More recently, in January 2014, several regions of the country were at the brink of serious power disruptions as a result of the “polar vortex” weather anomaly.⁶ These events highlight the potential risk to

³ Testimony of Philip D. Moeller, Commissioners, FERC, Senate Energy and Natural Resources Committee, Hearing on “Keeping the Lights On:- Are We Doing Enough to Ensure the Reliability and Security of the U.S. Electric Grid?” at 2 (Apr. 10, 2014) (Attachment A).

⁴ GAO, EPA Regulations and Electricity: Update on Agencies’ Monitoring Efforts and Coal-Fueled Generating Unit Retirements at 2-3 (Aug. 2014).

⁵ Electricity Consumers Resource Council, *The Economic Impacts of the August 2003 Blackout* (Feb. 2004). The blackout affected all or parts of Michigan, Ohio, Pennsylvania, New York, New Jersey, Connecticut, and Massachusetts.

⁶ North American Electric Reliability Corporation, *Polar Vortex Review* (Sept. 2014).

reliability that will occur if projected retirements of coal-fired EGUs are not immediately replaced on a one for one basis. Recent independent reliability assessments emphasize this point.

On November 5, 2014, the North American Electric Reliability Corporation (“NERC”) issued a preliminary review of the assumptions and potential reliability impacts of the proposed rule.⁷ NERC is an international regulatory authority established to evaluate and improve the reliability of the bulk power system (“BPS”) in North America.⁸ In the United States, NERC is subject to the oversight of FERC. NERC is required to conduct periodic assessments of the reliability and adequacy of the BPS. NERC’s recent review of the proposed rule is one such assessment. The NERC Report identifies three general concerns related to the changes in resource mix and the consequent reliability issues that would be forced by the proposed ESPS. First, NERC is concerned that the infrastructure improvements necessary to support more natural gas generation (both new NGCC and pipeline delivery capability) cannot be achieved in accordance with EPA’s proposed compliance schedule. NERC Report at 24-25. NERC expressed similar concern regarding the need for transmission infrastructure to accommodate increased natural gas and renewable generation. *See id.* at 20 (expressing concern that construction of new transmission lines could take as long as 15 years to complete).

Second, the proposed rule would constrain the availability of essential reliability services (“ERSs”), such as load following, regulation and ramping services.⁹ This outcome results from the intermittent nature of variable energy resources (“VERs”) such as wind and solar. While increased reliance on VERs should be met with an increase in reserve margins to maintain reliability, *id.* at 25, the proposed rule would result in reduced reserve capacity due to the retirement of coal-fired EGUs. NERC also noted that EPA’s estimate of retirements “may be conservative if the assumptions [in EPA’s Integrated Planning Model] prove to be unachievable. Developing suitable replacement generation resources to maintain adequate reserve margin levels may represent a significant reliability challenge, given the constrained time period for implementation.” *Id.* at 6. In another study, NERC and the California Independent System Operator (“ISO”) concluded that the reliability of bulk power supply can be diminished when

⁷ NERC, Potential Reliability Impacts of EPA’s Proposed Clean Power Plan: Initial Reliability Review (Nov. 2014) (“NERC Report”) (Attachment B).

⁸ The “bulk power system” is defined as “facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and electric energy from generation facilities needed to maintain transmission system reliability.” 16 U.S.C. §824o. The term does not include facilities used in the local distribution of electric energy.

⁹ Conventional generators with large rotating mass (steam, hydro, and combustion turbine technologies) provide ERSs needed to reliably operate the North American electric grid. ERSs represent “a necessary and critical part of the fundamental reliability functions that are vital to ensuring reliability, so these services must be identified, measured, and monitored so that operators and planners are aware of the changing characteristics of the grid and can continue its reliable operation.” *See* NERC, Essential Reliability Services Task Force: A Concept Paper on Essential Reliability Services that Characterizes Bulk Power System Reliability (Oct. 2014).

renewable resources reach 20% or more of total supply¹⁰—a number that EPA projects can be achieved or exceeded by 24 States.

Third, NERC warns that increases in distributed energy resources (“DERs”), such as rooftop photovoltaic arrays, under the proposed rule will pose significant challenges to system operators. *Id.* at 25-26. This resource cannot be dispatched and is generally invisible to the operator, but will rely on the “system” for backup services, placing a greater and unpredictable demand for ERSs.

One of NERC’s most important recommendations is the need for detailed system evaluations that yield a “clear understanding of the complex interdependencies resulting from the rule’s implementation.” *Id.* at 27. EPA’s modeling of its proposed rule assumptions is not a detailed system evaluation. The Integrated Planning Model (“IPM”) used by EPA lacks the granularity and realism capable of identifying the real risk of the proposed ESPS at the operational level. IPM dispatches on a seasonal basis using load duration curves and regional load shapes, which is a gross generalization of actual real-time dispatch practices. Further, IPM does not effectively model individual power plants, does not model the random intermittency of wind and solar, relies on an unrealistic, simplified industry structure (*i.e.*, 64 “model regions” in lower 48 States as proxies for the actual utilities and transmission operators), and relies on an even more simplified “model” of natural gas supply and demand. The necessary details to assess reliability are simply missing from EPA’s model.

In the absence of such necessary modeling by EPA, industry planning groups are beginning to prepare more detailed evaluations of the proposed ESPS’s potential impacts on grid reliability. For example, the Southwest Power Pool, Inc. (“SPP”)¹¹ and the Electric Reliability Council of Texas (“ERCOT”)¹² recently completed grid reliability analyses evaluating the likely impacts of the proposed rule. *See* SPP, Comments on “Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units,” (Oct. 9, 2014) (“SPP

¹⁰ Testimony of Gerry Cauley, President and CEO, NERC, Senate Energy and Natural Resources Committee, Hearing on “Keeping the Lights On- Are We Doing Enough to Ensure the Reliability and Security of the U.S. Electric Grid?” at 7 (Apr. 10, 2014) (citing NERC & California ISO, 2013 Special Reliability Assessment: Maintaining Bulk Power System Reliability While Integrating Variable Energy Resources – CAISO Approach (Nov. 2013)).

¹¹ SPP is a FERC-jurisdictional RTO and Regional Entity (“RE”) with delegated authorities to ensure the reliability of the bulk electric system within the SPP region. That region includes all or parts of eight States: Arkansas, Kansas, Louisiana, Missouri, Nebraska, New Mexico, Oklahoma, and Texas. SPP’s plenary function as an organization is maintaining reliability.

¹² ERCOT is an ISO that manages the flow of electric power for 24 million customers representing approximately 90% of Texas’ total electric load. Because ERCOT operates solely in Texas, it is not subject to FERC oversight.

Reliability Assessment”); ERCOT, ERCOT Analysis of the Impacts of the Clean Power Plan (Nov. 17, 2014) (“ERCOT Reliability Assessment”) (Attachment C).¹³

The SPP Reliability Assessment has two parts: (1) evaluation of transmission system impacts (*i.e.*, potential for bulk electric system equipment overloads and low voltages), and (2) evaluation of impacts to reserve margins. SPP determined that EPA’s assumptions in the proposed rule would impede reliable operation of the electric transmission grid in the SPP region, resulting in violations of NERC’s mandatory reliability standards and exposing the power grid to significant interruption or loss of load. These impacts result, in part, from the infeasibility of the compliance schedule in the proposal, which is too short to ensure the timely siting and construction of the necessary electric transmission, electric generation, and natural gas pipeline infrastructure within and across the appropriate planning areas.

SPP’s overall conclusion was that the proposed rule would pose a “serious risk” to reliability:

If the proposed CPP remains as is, the bulk electric system will be at serious risk of violating these limits [to ensure that transmission lines are not overloaded and voltage is maintained]. The likelihood that this outcome occurs dramatically increases if the timing of the issuance of the final rule effectively prevents the construction of electric system infrastructure necessary to facilitate compliance with the state goals being contemplated under the proposed CPP.

SPP Reliability Assessment at 2.

SPP conducted the transmission system impact evaluation in two parts. In the first part, SPP assumed available unused electric generation capacity that currently exists within the SPP region and surrounding areas would be used to replace the projected retired capacity. The second part of the transmission system impact evaluation assumed that the projected EGU retirements would be replaced by increased output of existing generation, including wind resources, and new generation capacity modeled according to resource planning information being utilized in SPP’s 10-year transmission planning assessment that is currently in progress. The assessment concluded:

The SPP region will experience numerous thermal overloads and low voltage occurrences under both scenarios studied. Results of the first part of the transmission system impact evaluation indicate that if the assumed EGU retirements were to occur absent requisite transmission and generation infrastructure improvements, the power grid would suffer extreme reactive deficiencies ... that would expose it to widespread reliability risks resulting in significant loss of load and violations of NERC reliability standards.

Id. at 4. Under the second scenario, SPP identified 38 overloaded elements in 6 States that SPP would have to mitigate through transmission planning. *Id.* at 5. The SPP

¹³ The ERCOT Reliability Assessment is a preliminary report, and ERCOT intends to release a full in mid-December. *Id.* at 2.

concluded that, “[unless the proposed CPP is modified significantly, SPP’s transmission system impact evaluation indicates serious, detrimental impacts on the reliable operation of the bulk electric system in the SPP region, introducing the very real possibility of rolling blackouts or cascading outages that will have significant impacts on human health, public safety and economic activity within the region.” *Id.* at 6.

SPP also evaluated the impacts of the projected EGU retirements on SPP’s reserve margin.¹⁴ SPP’s minimum required reserve margin is 13.6% per load-serving entity. SPP concluded “that by 2020 SPP’s reserve margin would fall below 4.7%, which is 8.9% below SPP’s minimum reserve margin requirement and would result in a violation of SPP’s reliability criteria and NERC reliability standards.” *Id.* at 7. By 2024, SPP estimated that its anticipated reserve margin would be -4.0%. *Id.* Similar challenges are expected for the Midcontinent Independent System Operator (“MISO”).¹⁵ The concerns over operating below NERC’s reserve capacity standards are particularly troubling, as States and system operators may be forced to decide whether to comply with EPA’s Section 111(d) rule or to comply with NERC’s reserve capacity requirements.

Likewise, ERCOT noted significant concerns with the proposed rule, explaining “that, given the ERCOT region’s market design and existing transmission infrastructure, the timing and scale of the expected changes needed to reach the CO₂ emission goals could have harmful impacts on reliability.” ERCOT Reliability Assessment at 1. In particular, ERCOT noted challenges associated with (1) the anticipated retirement of up to half of ERCOT’s existing coal-fired capacity, (2) integrating significant new intermittent wind and solar resources, and (3) infrastructure changes needed to address rapidly changing resource mixes. *Id.* at 2. In light of these concerns, ERCOT evaluated the potential impacts of the proposed rule under two different scenarios, one where the emissions limits were applied as a modeling constraint that selected cost-effective means of reducing carbon intensity and one where carbon emissions fees were imposed on EGUs. *Id.*

While ERCOT concluded that EPA’s emission reduction targets could be achieved over the long-term, it did identify significant reliability concerns associated with implementing the proposed rule and concluded that “it is evident that implementation of the proposed Clean Power Plan will have a significant impact on the planning and operation of the ERCOT grid.” *Id.* at 18. Specifically, ERCOT highlighted transmission challenges associated with the loss of existing generating capacity near major urban centers, reduction in reserve capacity if existing coal-fired EGUs are retired too quickly, and challenges associated with integrating additional renewable energy capacity. *Id.* In other words, even if the grid reliability challenges can be managed and

¹⁴ Reserve margin is the amount of generation capacity an entity maintains in excess of its peak load-serving obligation.

¹⁵ See Hannah Northey, *EPA Rules for coal-fired power may threaten Midwest reliability*, E&E Publishing (Sept. 19, 2014) (citing MISO, 2016 Resource Adequacy Forecast (June 5, 2014); Letter from Sandra Hochstetter Byrd, *et al.* to Hon. Gina McCarthy, Administrator, EPA at 2; Testimony of Philip D. Moeller, at 3 (Apr. 10, 2014).

resolved over the long term, EPA's aggressive compliance schedule will pose risks to ERCOT's ability to consistently supply consumers with reliable electricity.

NERC, SPP, and ERCOT are expert bodies whose mission requires them to evaluate the reliability of the electricity grid. Their substantial, well-documented concerns regarding electricity grid reliability issues highlight not only the unprecedented scope of the proposed rule, but also the risks it would create in an area where EPA has less significantly expertise than other federal agencies such as FERC or industry bodies such as NERC, SPP, and ERCOT. It is clear that potential reliability impacts have not been adequately addressed in the proposed rule or related technical support documents.

II. THE PROPOSED RULE IS ALREADY CAUSING IRREPARABLE HARM AND SHOULD BE WITHDRAWN

The aggressive emission reduction targets that EPA has proposed will cause significant and irreparable harm to the Associations' members. Although the final compliance date is not until 2030, EPA's proposal would require that the majority of emission reductions occur within a few years, meaning that immediate, rushed action on the part of the Associations' utility members is necessary to achieve those goals. There will be insufficient time to prudently plan a State's compliance measures, and no assurance that the electric grid will continue to operate on a safe and reliable basis. At a minimum, EPA must eliminate the interim compliance period to give States and affected EGUs sufficient time to develop and implement plans to reduce CO₂ emissions from the electricity sector. Further, the costs associated with the emission reductions will be significant and will force utilities to accelerate pre-existing plans to retire coal-fired EGUs and result in stranded assets, the cost of which may be passed on to consumers. In addition, the harm associated with this proposal will extend far beyond the affected EGUs and will also affect the Associations' members who supply materials to existing coal-fired EGUs, consume electricity produced by affected EGUs, and compete with affected EGUs for raw materials and feedstocks.

A. EPA's Proposed Compliance Schedules Are Unreasonable

By expanding the scope of the Section 111(d) program beyond the fence line of affected EGUs and focusing instead on emission reductions that can be achieved throughout the entire electricity sector, EPA is proposing a regulatory scheme that will force States to fundamentally restructure the way in which electricity is generated, transmitted, consumed, and regulated. While the Associations support EPA's proposal to provide States with additional time to prepare implementation plans, *see* 79 Fed. Reg. at 34915, the brief one or two year extensions proposed by EPA will not provide sufficient time for States to develop and finalize plans to implement the proposed rule. Moreover, the initial compliance deadlines, which could begin as little as two years after the States submit implementation plans (and much less than two years after EPA approves them) provide far too little time for the States to develop regulatory programs to administer the programs and for regulated entities to develop the additional infrastructure needed to reorganize electricity generation and transmission systems. To ensure that States and regulated entities have sufficient time to develop implementation plans and install the necessary infrastructure to achieve EPA's emission reduction targets, the Associations urge EPA to extend

the deadline for submitting State implementation plans until at least four years after EPA issues a final Section 111(d) rule and to eliminate entirely the interim compliance period.

In any event, EPA should provide all States with the same opportunities to extend the deadline for submitting implementation plans. The time needed to develop satisfactory State plans are largely the same, regardless of whether States elect to participate in a multi-State plan. By offering multi-State plan participants an extension that is twice as long as States that submit individual plans, EPA is creating a powerful incentive for States to adopt multi-State plans. This is particularly true because the two-year deadline for individual plans will, in most cases, be unachievable, and States that pursue individual implementation plans will be at risk of EPA establishing a federal implementation plan if the deadline is missed. EPA should not use different compliance deadlines to direct States toward the Agency's preferred implementation approach. If EPA is truly committed to giving States the flexibility and autonomy contemplated under Section 111(d), it must take a neutral position with respect to the various compliance options and allow the States to select an implementation approach based solely on the merits of the approach.

1. States Cannot Achieve EPA's Aggressive Schedule for Submitting Implementation Plans

By proposing deadlines for State implementation plans that are only two or three years after EPA finalizes this rulemaking, the Agency greatly underestimates the challenges faced by the States. Unlike prior Section 111(d) rules that required States to develop implementation plans for affected facilities, the proposed rule would require States to fundamentally restructure the entire electricity sector. Even under optimal political and regulatory conditions, it will take years for States to complete all of the legislative and regulatory actions that are necessary to develop satisfactory implementation plans. And many States operate under less than optimal conditions, which will only add to the time constraints that those States face. Thus, at a minimum, EPA must give the States at least four full years after finalizing the rule to submit implementation plans.

In many States, regulatory agencies currently lack the authority to develop implementation plans that would be capable of achieving EPA's proposed emission reduction targets, and legislative action would be needed to achieve EPA's emission reduction goals. At a minimum, State legislatures would be required to establish or revise RPS and energy efficiency resources standards ("EERS") programs to meet EPA's targets for each State (as opposed to existing targets which may fall short of EPA's goals). For many States, even more legislative changes will be required. For example, legislation may be needed to give State public utilities commissions ("PUCs")¹⁶ or other comparable agencies regulatory authority over municipally-owned EGUs. Likewise, States may need to fundamentally change current dispatching

¹⁶ PUCs are State regulatory bodies that are responsible for regulating the rates and services of public utilities. They implement State laws governing the public utility sector. PUCs play a central role in regulating EGUs at the State level, regardless of whether the State's utilities operate in a vertically integrated or competitive market system and regardless of whether dispatching decisions are ultimately made at a regional level by an RTO.

requirements based on least-cost bidding to allow PUCs to dispatch higher-cost forms of generation over lower cost forms of generation. Further, for States that participate in RTOs, additional steps may be required to modify RTO dispatching priorities and obtain approval from FERC. *See* 16 U.S.C. §§ 824d, 824e. Taken together, these legislative changes may well amount to a wholesale restructuring of a State's electricity generation and transmission sectors. These changes cannot take place overnight. History shows that legislative changes of this order takes months, if not several years, and can frequently require action over multiple legislative sessions. Likewise, developing the necessary regulatory structure once appropriate legislation is passed can take several years, particularly when comprehensive public participation requirements must be met. Thus, even under optimal conditions, EPA's two-year deadline to submit a State implementation plan is unduly aggressive and unlikely to be met by more than a handful of States with legislation already in place to allow implementation plans to be developed solely through regulatory efforts.

The time constraints associated with completing the necessary legislative and regulatory action to prepare a satisfactory implementation plan are exacerbated in States with part-time legislatures that have limited time to consider and enact the sweeping legislation that will, in many cases, be needed to implement the proposed rule. Here, the case of Texas is both instructive and representative of other States. Texas has a part-time legislature that meets every other year for six months. Texas' next legislative session is scheduled to begin on January 13, 2015 and end on June 1, 2015.¹⁷ Under the current schedule, the legislative session will end on the day that EPA is scheduled to finalize the ESPS rule and the legislature is not scheduled to meet again until January of 2017.¹⁸ Thus, even if the legislature were able to overhaul its existing energy laws by revising its competitive market structure and enacting RPS and EERS programs during the 2017 legislative session, the State regulatory agencies would only have, at most, a few months to develop, propose, and finalize a State implementation plan. This is virtually impossible, given the procedural requirements that accompany such regulatory initiatives. Putting aside the substantive requirements that must accompany any proposed rule, *see* Tex. Gov't Code § 2001.024, an agency must give the public 30 days to comment on any proposed rule, *see id.* §§ 2001.023, .029, and must respond to substantive comments, *see id.* § 2001.033. Such a complicated undertaking cannot be completed in a matter of months.

Furthermore, given the sweeping scope of the proposed rule, a satisfactory implementation plan may require the coordination of multiple State agencies. The State agencies responsible for managing and dispatching electricity generation may be different than the agencies responsible for implementing renewable energy programs or energy efficiency initiatives. Thus, even after appropriate legislative programs are in place, determining which agencies are responsible for developing implementation plans and successfully coordinating between them will take additional time. In Montana, for example, developing an implementation

¹⁷ *See* Legislative Reference Library of Texas, Texas legislative sessions and years, *available at* <http://www.lrl.state.tx.us/sessions/sessionyears.cfm> (last visited September 16, 2014).

¹⁸ Given this legislative schedule, it is difficult to see how Texas could propose a satisfactory initial State plan by June 30, 2016, *see* 79 Fed. Reg. at 34,915-16, without knowing what action, if any, the State legislature will take in the next legislative session.

plan “would require coordination between the Public Service Commission, the Department of Environmental Quality, the self-governing electric cooperatives, and public power entities of the State of Montana,... the Governor’s Office, [and] the Department of Commerce.”¹⁹ The interagency coordination that may be needed to develop an implementation plan may add months, if not years, to the overall regulatory process.

Finally, EPA’s proposal to add one additional year for States seeking to establish multi-State implementation plans falls far short. In addition to the State-specific challenges described above, the intrastate negotiations needed to establish and authorize a memorandum of understanding, a final agreement on a multi-State plan and, in all likelihood, a new intrastate organization to implement the program will take far more than one additional year. Indeed, depending on the structure of the multi-State agreement, Congressional approval may also be required under the Interstate Compact Clause. *See* U.S. Const. Art I, Sec. 10, cl. 3. Here, California’s linkage of AB32 with Quebec is instructive. The Western Climate Initiative, which included California and Quebec, along with other States and Provinces, was initiated in February 2007.²⁰ Although California adopted AB32 in 2006, it took the California Air Resources Board (“CARB”) five years (until October 2011) to adopt cap-and-trade regulations to implement AB32. CARB did not propose regulations to link California’s cap and trade program with Quebec for another seven months, and then took nearly a year and a half to finalize the linkage²¹ and hold the first joint auction in November 2014. In light of California’s six-year process for establishing a multi-State program to reduce GHG emissions, it is unreasonable for EPA to set a three-year deadline for States to reach similar agreements under the proposed rule.

Rather than providing unmanageably short deadlines for submittal of State plans, EPA should take a flexible approach with deadlines that will ensure that States have the time necessary to complete the legislative and regulatory actions needed to prepare a satisfactory implementation plan. At a minimum, EPA should offer *all* States at least four years to submit an implementation plan, regardless of whether they intend to submit a single- or multi-State plan. Further, EPA should provide States with the opportunity to extend these deadlines, provided they can show continued progress toward development of a satisfactory State plan.

¹⁹ Transcript of “State Perspectives: Questions Concerning EPA’s Proposed Clean Power Plan,” U.S. House of Representatives, Committee on Energy and Commerce, at 86 (Sept. 9, 2014), available at <http://docs.house.gov/meetings/IF/IF03/20140909/102623/HHRG-113-IF03-Transcript-20140909.pdf>.

²⁰ *See, e.g.*, California Air Resource Board, Proposed Amendments to the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms to Allow for the Use of Compliance Instruments Issued by Linked Jurisdictions: Staff Report: Initial Statement of Reasons 14 (May 9, 2012), available at <http://www.arb.ca.gov/regact/2012/capandtrade12/isormainfinal.pdf>.

²¹ *See* CARB & Quebec, *Agreement Between the California Air Resources Board and the Gouvernement du Quebec Concerning the Harmonization and Integration of Cap-and-Trade Programs for Reducing Greenhouse Gas Emissions* (September, 2013), available at http://www.arb.ca.gov/cc/capandtrade/linkage/ca_quebec_linking_agreement_english.pdf.

2. EPA Must Eliminate Its Interim Compliance Targets

EPA also significantly underestimates the time that States will need to implement the emission reduction programs contemplated by the proposed rule. Due to a combination of legislative, regulatory, and infrastructure challenges, it will be infeasible for States to achieve the interim compliance targets set by EPA, particularly in the earlier years of the interim compliance period. In light of the steep emission reductions that EPA projects beginning in 2020, States that cannot meet those initial targets will be forced to undertake much more extensive and costly emission reductions in the later part of the interim compliance period in order to meet EPA's overall emission reduction target. In order to make up for higher emissions at the beginning of the interim period, States may have to impose emissions limits that are even more stringent than the final 2030 targets set by EPA at the end of the interim period in order to meet EPA's average interim target. Rather than requiring States to mandate expensive emission reductions that will likely be more stringent than the final 2030 compliance targets, EPA should eliminate the interim compliance period and allow States to focus their plans solely on identifying efficient and cost-effective approaches to achieving the final compliance targets.

First, as discussed above, EPA's proposed timeline for the submission of State implementation plans is unreasonable. Even under the best circumstances, States will need far more than two years to complete all of the legislative and regulatory actions necessary to develop comprehensive implementation plans for the entire electricity sector. Policy differences within legislatures and regulatory agencies could further delay the development of implementation plans in many States. Finally, even after a State implementation plan is submitted, EPA's review of those plans will add further delay. EPA routinely takes more than a year to approve SIPs under Section 110, and frequently takes more than two years to do so. Because the content of a State's implementation plan will remain uncertain until after EPA approval, this lengthy review process will further delay investments in the projects and infrastructure necessary to comply with EPA's emission reduction targets.²² Such investments will be delayed even further in the event that EPA disapproves a State plan and must then develop a federal implementation plan in its place.

Second, even after an implementation plan is approved, it will take States and regulated entities several years to develop the infrastructure necessary to reduce overall CO₂ emissions from the electricity sector. The new natural gas pipelines that will be needed to ensure a sufficient supply of gas to run NGCC facilities at a 70% capacity factor can be expected to take several years to construct. As an example, the recently announced Atlantic Coast Pipeline—which will run 550 miles from West Virginia to North Carolina—is expected to take a minimum of four years to complete construction, assuming that there are no problems during the permitting process.²³ Likewise, new transmission lines needed to connect existing NGCC facilities and new

²² For the same reasons, EPA's suggestion in the NODA that States could “achiev[e] some reductions earlier than 2020 to allow for a more gradual reduction of emissions between 2020 and 2030” is unlikely to provide any material benefit to the States.

²³ Dominion Energy, Atlantic Coast Pipeline, available at <https://www.dom.com/business/gas-transmission/atlantic-coast-pipeline/index.jsp> (last visited September 16, 2014).

renewable energy facilities to demand centers currently served by coal-fired EGUs will take many years to complete. For example, Texas' CREZ project, which involved installation of new transmission lines needed to transmit 18.5 MW of wind power from west Texas and the Texas panhandle to key population centers, took more than six years to construct after legislative approval.²⁴ Likewise, "[i]n the SPP region, as much as eight and a half years to study, plan for and construct new transmission facilities has been required."²⁵ These projects—and the time needed to complete them—are not unusual and represent the types of infrastructure investments that will be needed to achieve the aggressive emission reduction goals proposed by EPA. Under the circumstances, it is highly unlikely that a State could enact new legislation, develop an implementation plan, obtain EPA approval, and complete massive infrastructure projects in less than a decade. Thus, even if EPA completes the rulemaking on schedule, States would not be prepared to implement significant portions of their plans until 2025, or halfway through the interim compliance period.

EPA cannot dismiss the challenges this will pose for achieving the interim emission reduction targets by simply asserting that States can require more aggressive emission reductions at the end of the interim compliance period. *See, e.g.*, 79 Fed. Reg. at 34,897. The emission reductions required by EPA are far from gradual because EPA assumes that Building Blocks 1 and 2 will be fully implemented at the beginning of the interim compliance period in 2020. As a result, EPA assumes that, on average, 63% of the final emission reductions will be achieved by 2020.²⁶ EPA may be technically correct that, because the interim compliance period evaluates average emissions over a 10-year period, a State that is unable to meet these aggressive emission reductions in the early years of the interim compliance period can make up for that shortfall by imposing more stringent emission reductions in the latter years. However, this may not be possible in practice, as it will force States to "over comply" in the latter years of the interim period by achieving emission reductions that are well below EPA's projections for those years. Not only will such over-compliance result in a significant increase in compliance costs, it will likely force States to impose emission reductions at the end of the interim compliance period that will exceed the final emission reduction targets that would be applicable to the States beginning in 2030. It makes little sense to require a State to exceed the final emission reduction targets for a year or more simply because it was infeasible to achieve EPA's proposed emission reduction targets for the earlier years of the interim compliance period.

Recognizing that infrastructure challenges will make the interim compliance deadlines infeasible in many circumstances, EPA suggests in the October 30, 2014 Notice of Data

²⁴ Public Utility Commission of Texas, CREZ Transmission Program Information Center, available at <http://www.texascrezprojects.com/default.aspx> (last visited September 16, 2014).

²⁵ SPP Comments at 8.

²⁶ Data taken from EPA, Data File: Goal Computation –Appendix 1 and 2 and EPA, Goal Computation Technical Support Document (comparing 2012 Fossil, RE, at risk Nuclear with Step 6&7 (State Goal Phase I & II (lbs/MWh)) for 2020 and 2030), available at <http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-technical-documents>.

Availability (“October 30th NODA”) that “a phase-in schedule could be developed for Building Block 2 on the basis of whether, and to what extent, any additional infrastructure improvements (e.g., natural gas pipeline expansion or transmission improvements) are needed to support more use of existing natural gas-fired generation.” 79 Fed. Reg. 64,543, 64,548 (Oct. 30, 2014). However, the approach proposed in the NODA is inadequate to address the significant obstacles with the proposed compliance schedule. Given the economic, technological, and legal complexities of large-scale infrastructure projects, it would be unreasonable for EPA to force States to commit to a specific schedule for these projects at this initial stage of the Section 111(d) process. Under such a phase-in approach, any legal challenge or unforeseen complication during the construction process could threaten a States’ ability to comply with a phase-in interim target. Furthermore, the NODA does not provide significant flexibility beyond natural gas infrastructure issues—such as the time needed for legislative and regulatory action to prepare implementation plans, *see* Section II.A.1., *supra*—to enable the necessary time to achieve the interim compliance goals. Instead, EPA should withdraw the interim compliance goals and allow States to focus exclusively on developing a pathway to achieve the final emission reduction targets by 2030.

B. The Proposed Rule Is Causing Irreparable Harm To Affected EGUs

In the proposed rule, EPA adopts an aggressive compliance schedule that will require States and affected EGUs to complete the lions’ share of the required emission reductions within a few short years after the rule is finalized and State implementation plans are submitted to EPA. While EPA includes a 10-year interim compliance period and does not impose a final emission reduction target until 2030, this so-called glide path only applies to emission reductions associated with renewable energy and demand-side energy efficiency. In contrast, EPA projects that all emission reductions associated with heat rate improvements at existing coal-fired EGUs and all redispatch from coal-fired EGUs to NGCC turbines will be completed before the initial 2020 compliance deadline. 79 Fed. Reg. at 34,905-06. Thus, what might appear on the surface to be a smooth transition over time actually resembles a cliff, as nearly two-thirds of the emission reductions required by EPA must occur in the next five years (*i.e.*, by January 1, 2020).²⁷

States and affected EGUs will have to take immediate action to implement the proposed rule if States are to achieve EPA’s projected emission reduction targets and fully implement Building Blocks 1 and 2 by the initial January 1, 2020 compliance date. As an initial matter, the heat rate improvements contemplated by EPA cannot be implemented overnight. Instead, these projects require careful planning and may require affected coal-fired EGUs to be offline for a significant period of time to make the necessary operational changes. For larger utilities and for States with significant coal-fired generating capacity, there are significant logistical concerns associated with implementing heat rate improvements on such a large scale, and, as NERC asserts, the outcome may be earlier retirements of coal-fired EGUs than EPA assumes, “which creates additional uncertainty in future generation resources.” NERC Report at 8. To ensure grid reliability, heat rate improvements will have to be staggered over time so that sufficient

²⁷ Data taken from EPA, Clean Power Plan Proposed Rule Technical Support Documents, Data File: Goal Computation – Appendix 1 and 2 (XLS), available at <http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-technical-documents>.

generating capacity remains online to meet consumer demand. In addition, bottlenecks may occur if facilities seeking to implement heat rate improvements exceed the supply of labor and materials needed to install those improvements. Thus, to ensure that all affected coal-fired EGUs can make the necessary changes by 2020, utilities—working in concert with States, ISOs, and RTOs—will have to begin planning and implementing these changes immediately upon finalization of the rule.

Likewise, immediate action will be needed to implement Building Block 2. In some markets, significant infrastructure improvements will be necessary to ensure that existing NGCC facilities can reliably run at a 70% capacity factor and provide electricity to the consumers who demand it. First, new pipeline infrastructure will be necessary in some cases to ensure that there are sufficient supplies of natural gas to meet demand. NGCC facilities depend on real-time delivery of natural gas, and existing pipeline capacity may not be able to accommodate an increase in capacity to 70%, particularly on a seasonal basis when demand for natural gas is strong in other sectors. Likewise, existing NGCC facilities are rarely co-located with the coal-fired EGUs whose generation they will replace. As a result, in some cases, additional transmission lines will be necessary to ensure that these facilities can transmit electricity to the consumers currently served by coal-fired EGUs. As described above, such large-scale infrastructure projects routinely take five or more years to complete. Thus, to meet a 2020 compliance deadline, States and affected EGUs will need to begin implementing these changes as soon as EPA finalizes the rule.

Further, utilities with coal-fired EGUs will face immediate questions regarding the retirement of existing facilities in the face of an EPA-mandated reduction in demand for coal generation. EPA projects that, in addition to the coal-fired EGU retirements expected in response to existing environmental regulations such as MATS, as many as 49 GW of coal generating capacity—representing 19% of the current coal generation fleet—will be retired as a result of this proposal.²⁸ And, to meet EPA’s emission reduction targets, these retirements must occur by 2020—not by 2030 when the interim compliance period ends. Further, even if utilities had plans to retire some of their generating capacity, this rule will accelerate the retirement schedule and increase the costs associated with the transition from existing coal-fired EGU capacity to other sources of electricity. For facilities scheduled for retirement over a longer time scale and facilities that were not projected to be retired at all, there will be a significant cost in the form of stranded assets as these facilities will be retired before the end of their remaining useful lives. Indeed, the costs will likely be exacerbated for facilities that have only recently spent millions of dollars to comply with MATS and other EPA regulations. These utilities will suffer significant economic harm if they cannot recoup their investments before being forced to retire their coal-fired EGUs.

C. If Finalized, The Rule Would Harm The Associations’ Members In The Manufacturing And Industrial Sectors

Due to their close relationship with the electricity sector, many of the Associations’ members in the manufacturing sector would be directly and adversely affected if the proposed

²⁸ EPA, Regulatory Impact Analysis at 3-32 (June 2014)

rule were finalized. First, the manufacturing sector consumes 26% of the electricity produced in the United States,²⁹ making it particularly susceptible to changes in the price of electricity. Likewise, the manufacturing sector consumes 29% of the natural gas in the United States,³⁰ making it a direct competitor of the NGCC facilities that EPA projects will grow significantly as a result of this proposal. In light of these facts, the impacts of the rule are obvious. EPA projects that the rule will increase electricity prices by as much as seven percent. 79 Fed. Reg. at 34,934. EPA also projects that increasing NGCC utilization rates will put upward pressure on natural gas prices and projects that, under a 70% NGCC capacity goal, prices will rise by as much as ten percent during the interim compliance period. 79 Fed. Reg. at 34,895; *see also* RIA at ES-24 (projecting increases of as much as twelve percent). Moreover, EPA's projections likely understate the significance of the price increases associated with the rule. For example, even without considering costs associated with transmission upgrades and natural gas infrastructure upgrades, ERCOT has projected that electricity costs to consumers may increase by as much as 20%.³¹ As a result, the Associations' members in the manufacturing and industrial sectors may face significant price increases both in electricity and in other necessary feedstocks, making them vulnerable to international competition.³²

The impact of the proposed rule is further exacerbated for industrial sectors that, in addition to being energy intensive, are also trade exposed. These sectors include, among others, chemical, plastics, steel, iron ore, aluminum, paper, food and beverage processing, nitrogen fertilizer, glass, industrial gases, oil refining, and cement.³³ Because trade exposed industries face stiff competition from overseas, even small changes in costs can have a significant effect on a sector's international competitiveness and result in a significant decrease in domestic market share. For the industry sectors mentioned above, a seven percent increase in electricity costs could be particularly troublesome, especially when combined with increases in natural gas prices and the incremental costs to fossil fuel-fired EGUs associated with complying with other federal environmental regulations such as MATS and CSAPR that will also be passed on to consumers.

²⁹ Industrial Energy Consumers of America ("IECA"), A Manufacturing Perspective on EPA's "Clean Power Plan" – Proposed GHG Regulation for Existing Electricity Generating Units 3 (July 30, 2014), available at http://www.ieca-us.com/wp-content/uploads/07.30.14_IECA-Perspective-on-GHG-Existing-Sources-Rule.pdf.

³⁰ *Id.*

³¹ ERCOT Reliability Analysis at 18.

³² As discussed in Section XIII.B., *infra*, EPA's partial economy modeling in the Regulatory Impact Analysis fails to address the effect that the proposed rule would have on many of the Associations' members. If EPA decides to proceed with this rulemaking, the Associations urge EPA to evaluate (or direct the States to evaluate) the effect that the rule will have on energy intensive, trade exposed industries and to take appropriate steps to minimize undue impacts on those industrial sectors.

³³ IECA, at 6 (noting that these 12 industrial sectors consume 15.8% of the United States' total electricity).

EPA actions that adversely affect the competitiveness of trade exposed industries are also inconsistent with the Obama administration's broader policy priorities to increase exports and attract foreign direct investment.³⁴

In addition, some of the Associations' members supply materials to coal-fired EGUs and will be harmed by the decrease in coal-fired EGU generation that the proposed rule would cause. For example, petroleum coke—a product produced during petroleum refining—is an energy feedstock that can be combusted in solid fuel EGUs in the same manner as coal. A regulation that reduces demand for coal by 25% or more will have a similar effect on petroleum coke. As a result, the Associations' petroleum coke-producing members will be harmed both by the lack of demand for petroleum coke and by the accompanying price reduction that will result from oversupply.

Further, as explained in Section I., *supra*, the proposed rule also raises serious questions with respect to grid reliability. For many of the Associations' members, reliable electricity is an absolute business necessity and electricity outages cannot be tolerated. Regardless of whether concerns over grid reliability come to fruition, the Associations' members will have to develop contingency plans to prepare for that potential. Such plans—and the necessary investments in alternative electricity supply options—will also prove costly and add to the economic harm that the proposed rule would cause if finalized.

Finally, the Associations' members may also be harmed if EPA adopts a portfolio approach that allows States to directly regulate entities other than affected EGUs. 79 Fed. Reg. at 34,853. As noted above, many of the Associations' members operate in energy intensive sectors that would be particularly susceptible to a portfolio approach. Given the aggressive nature of EPA's proposed emission reduction targets, States will have no choice but to pursue demand-side energy efficiency improvements. Under those circumstances, States may be inclined in their implementation plans to focus their electric utilities' energy efficiency efforts on energy intensive industry sectors because, from a regulatory perspective, it may appear more efficient to focus on a limited number of large industrial sources. Association members who build residential and commercial structures may also feel unduly targeted by federally enforceable energy efficiency measures. However, such efforts can be counterproductive. The higher rates that industrial consumers pay to their utility to comply with the State-mandated energy efficiency programs or RPSs reduce the funds available to the industrial consumer for investing in higher value projects that may be more aligned with EPA's GHG emission reduction objectives.³⁵ Therefore, the Associations urge EPA to discourage States from relying on

³⁴ See, e.g., Press Release, U.S. Dept. of Commerce, Deputy Secretary Andrews Promotes SelectUSA and Fostering Foreign Investment at APEC Meeting in Beijing (Nov. 10, 2014), available at <http://www.commerce.gov/blog/2014/11/10/deputy-secretary-andrews-promotes-selectusa-and-fostering-foreign-investment-apec-be>; International Trade Association, National Export Initiative Fact Sheet, available at <http://trade.gov/nei/nei-fact-sheet.asp>.

³⁵ Electricity Consumers Resource Council, Financing Clean Energy Investments of Large Industrial Customers: What is the Role of Electric Utilities? Washington, DC: 2010.

mandatory energy efficiency programs aimed solely at industrial facilities in their implementation plans.

III. EPA LACKS AUTHORITY TO ISSUE SECTION 111(d) REGULATIONS FOR SOURCE CATEGORIES ALREADY SUBJECT TO REGULATION UNDER SECTION 112

The proposed rule is unlawful, arbitrary, and capricious because the Clean Air Act prohibits EPA from regulating existing sources under Section 111(d) if those sources are also part of a source category that is subject to regulation under Section 112. On February 16, 2012, EPA published the final MATS rule for power plants, which subjected existing fossil fuel-fired EGUs to stringent and costly emissions limitations under Section 112. *See* 77 Fed. Reg. 9,304 (Feb. 16, 2012). Because these power plants are now regulated under Section 112, the Clean Air Act bars EPA from regulating them under Section 111(d).

First, under the plain meaning of Section 111(d), EPA lacks the legal authority to regulate existing facilities under Section 111(d) as those sources are already subject to a National Emissions Standard for Hazardous Air Pollutants (“NESHAP”) under Section 112. Second, nothing in the 1990 amendments to the Clean Air Act permits EPA to depart from the plain meaning of the statute and apply Section 111(d) more broadly to sources already subject to Section 112 NESHAPs. Third, because the proposed rule would impose significant burdens on the electricity sector, other manufacturing sectors, and the States, policy reasons also dictate that Section 111(d) be interpreted in a manner that is consistent with the plain meaning of the statute.

A. The Plain Meaning Of Section 111(d) Prohibits EPA From Establishing Emissions Guidelines For Source Categories Regulated Under Section 112

The Clean Air Act expressly prohibits EPA from regulating GHG emissions from fossil fuel-fired power plants under Section 111(d) because, as a result of the finalization of the MATS rule, those source categories are already regulated under Section 112. Section 112 authorizes EPA to establish NEHSAPs to regulate hazardous air pollutants (“HAPs”) from specific source categories. The authority to regulate emissions from certain sources under Section 111(d) is, in turn, defined by the scope of Section 112. In short, Section 111(d) preempts the regulation of existing sources under the NSPS program if those sources are already regulated under Section 112.

Specifically, Section 111(d) provides:

(1) The Administrator shall prescribe regulations which shall establish a procedure similar to that provided by Section 7410 of this title 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 7408(a) or *emitted from a source category which is regulated under 7412* but (ii) to which a standard of performance would apply

42 U.S.C. § 7411(d) (emphasis added). The plain meaning of this provision prohibits EPA from promulgating emissions guidelines for existing sources under Section 111(d) if the *source*

category is regulated under Section 112. This straightforward interpretation of Section 111(d) has been supported by the courts and consistently implemented by EPA.

In *American Electric Power Co. v. Connecticut*, 131 S. Ct. 2527 (2011), the Supreme Court endorsed a plain meaning interpretation of Section 111(d) that focuses on whether a source category is subject to a NESHAP under Section 112. After describing generally EPA’s authority to regulate existing sources under Section 111(d), the Court noted that “[t]here is an exception: EPA may not employ § [111(d)] if existing stationary sources of the pollutant in question are regulated under the national ambient air quality standard program, §§ [108-110], or the ‘hazardous air pollutants’ program, § [112]. See § [111(d)(1)].” *Id.* at 2537 & n.7. Thus the Supreme Court agreed that EPA cannot regulate pollutants emitted from existing sources under Section 111(d)—whether HAPs or non-HAPs—if the source category is regulated under Section 112.

Likewise, EPA has consistently complied with this interpretation in the past. With only two exceptions, there are no Section 112 source categories that are also subject to regulation under Section 111(d). For those two exceptions—pulp mills and municipal solid waste landfills—Section 111(d) performance standards preceded the Section 112 NESHAP for that source category. EPA published Section 111(d) guidelines for Kraft Paper Mills in May 1979 after it established performance standards for new sources under Section 111(b). See 44 Fed. Reg. 29,828 (May 22, 1979). EPA did not establish a Section 112 NESHAP for this category until 1998. 63 Fed. Reg. 18,503 (Apr. 15, 1998). Likewise, EPA issued the Section 111(d) emissions guidelines for municipal solid waste landfills in 1999, 64 Fed. Reg. 60,689 (Nov. 8, 1999), more than three years before it established a Section 112 NESHAP for the source category, 66 Fed. Reg. 2,227 (Jan. 16, 2003). Simply put, EPA has never before issued Section 111(d) regulations for a source category that was already subject to regulation under Section 112.

B. The 1990 Amendments To The Clean Air Act Do Not Give EPA Discretion To Depart From The Plain Meaning Of Section 111(d)

In an effort to justify its departure from the Section 111(d)’s plain meaning in the proposed rule, EPA relies on the process for enactment of the 1990 CAA amendments, which included two different provisions amending Section § 111(d), referred to as the House and Senate amendments. The Senate amendment adjusted the cross reference to Section 112 and prohibited EPA from establishing Section 111(d) regulations “for any existing source for any air pollutant ... included on a list published under section ... 7412(b).” Pub. L. No. 101-549, § 302(a), 104 Stat. 2399, 2474 (1990). The House amendment prohibited EPA from establishing Section 111(d) regulations “for any existing source for any air pollutant ... emitted from a source category which is regulated under Section 112.” Pub. L. No. 101-549, § 108(g), 104 Stat. at 2467. As explained below, EPA is wrong that the Senate amendment provides a basis for ignoring the plain text of the U.S. Code. Foremost, the Senate amendment is a drafting error that should not be given any effect. But even if the two amendments should both be considered effective, under traditional canons of statutory construction, the House amendment can and must be given full effect because the two amendments are complementary.

1. The House Amendment Must Be Given Full Effect Because the Senate Amendment Is a “Drafting Error”

While the 1990 CAA amendments included two revisions to Section 111(d), they cannot be given equal weight. Instead, because the Senate amendment is a “drafting error,” it must be disregarded, and the substantive House amendment must be given full effect. *See United States v. Ron Pair Enters., Inc.*, 489 U.S. 235, 242 (1989); *Am Petroleum Inst. v. SEC*, 714 F.3d 1329, 1336-37 (D.C. Cir. 2013); *Appalachian Power Co. v. EPA*, 249 F.3d 1032, 1041 (D.C. Cir. 2001). When the House and Senate amendments are viewed in their proper context, it is clear that the Senate amendment is nothing more than a scrivener’s error that must yield to Congress’ intent as expressed in the House amendment.

The 1990 CAA amendments included substantive changes to Section 112. Among them was the deletion of Section 112(b)(1)(A), which included a list of HAPs that were subject to regulation under Section 112. This list was replaced by Subsections 112(b)(1), (b)(2), and (b)(3). Because of this change, Section 111(d)’s cross-reference to Section 112(b)(1)(A) was no longer valid, and the Senate added a “conforming amendment” providing that “Section 111(d)(1) of the Clean Air Act is amended by striking ‘[112](b)(1)(A)’ and inserting in lieu thereof ‘[112](b).’” Pub. L. No. 101-549, § 302(a). A “Conforming Amendment” is an “amendment of a provision of law that is necessitated by the substantive amendments of the provisions of the bill.” Senate Legislative Drafting Manual § 126(b)(2)(A). Thus, the Senate amendment to Section 111(d) was intended to do nothing more than update the cross-reference to Section 112 to reflect the substantive changes made to that section. Indeed, the Senate formulation was treated as a mere conforming amendment in each draft of the Senate bill, including the April 3, 1990 draft, which the Senate passed. *See* 136 Cong. Rec. S27-02 (Jan. 23, 1990); 136 Cong. Rec. S2030-02 (Mar. 5, 1990); 136 Cong. Rec. S4363-02 (Apr. 18, 1990).

In contrast, as EPA has recognized, the House amendment “*substantively* amended section 111(d).” 70 Fed. Reg. 15,994, 16,031 (Mar. 29, 2005) (emphasis added). While the pre-1990 version of Section 111(d) referenced a specific list of pollutants in Section 112, the House amendment prohibited EPA from using Section 111(d) to regulate any pollutant “emitted from a source category which is regulated under section 112.” Pub. L. No. 101-549, § 108(g). This formulation appeared in the final bill passed by the House—in a substantive provision rather than in a conforming amendment. *See* 136 Cong. Rec. H2771-03 (May 23, 1990). The two chambers then appointed conferees to address the differences between the House and Senate bills. The revised bill that emerged from the joint conference committee contained both the House amendment (again, in a substantive provision) and the Senate amendment (still in a conforming amendment). *See* H.R. Conf. Rep. 101-952 (1990), *reprinted in* 1990 U.S.C.C.A.N. 3867. As EPA has previously acknowledged, this was simply an oversight: although the House approach to regulating utility units under Section 112 prevailed over the Senate approach in the joint conference, *see* 70 Fed. Reg. at 16,030-16,031, “[t]he Conference Committee never resolved the differences between the two amendments [to Section 111] and both were enacted into law,” *id.* at 16,030.

EPA has never disputed that a “literal reading” of the House amendment means that “EPA c[an] not regulate any air pollutant from a source category regulated under section 112.” EPA, Legal Memorandum for Proposed Carbon Pollution Emission Guidelines for Existing

Electric Utility Generating Units 26 (June 2014) (“Legal Memo”); *see also* 70 Fed. Reg. at 16,032 (“[A] literal reading of the House language would mean that EPA cannot regulate HAP or non-HAP emitted from a source category regulated under section 112.”). And EPA has previously acknowledged that the inclusion of the Senate’s conforming amendment was a “drafting error” because the corrected cross-reference to Section 112 was rendered unnecessary due to the substantive House amendment. 70 Fed. Reg. at 16,031. But EPA errs in claiming that, although “the Senate amendment to section 111(d) is a drafting error and therefore should not be considered, we must attempt to give effect to both the House and Senate amendments.” *Id.* Where a drafting error is identified, a court or an agency *must* give effect to “the intention of the drafters, rather than the [statutory] language.” *Ron Pair Enters., Inc.*, 489 U.S. at 242. As EPA concedes, the Senate amendment is “demonstrably at odds with the intentions of” Congress as expressed in the House amendment; thus, EPA must disregard the erroneous Senate amendment. *See id.*; *United States v. Wallace & Tiernan, Inc.*, 349 F.2d 222, 226 (D.C. Cir. 1965) (explaining that because some errors will inevitably occur in the process of revising earlier legislation, the court “need not and ought not translate what is essentially a clerical oversight into a congressional intention”).

The D.C. Circuit has explained that such scrivener’s errors are not uncommon in “enormous and complex statute[s],” and cannot “creat[e] an ambiguity” in an otherwise unambiguous statute. *Am. Petroleum Inst.*, 714 F.3d at 1336-37. Thus, Section 111(d), as included in the U.S. Code, accurately depicts Congress’ intent by including the substantive House amendment. After first incorporating the House’s substantive amendment, the codifier of the U.S. Code correctly noted that the Senate’s conforming amendment “could not be executed,” Revisers Note, 42 U.S.C. § 7741, because the intended cross reference was deleted by the House amendment. Thus, when the legislative history and broader context of the 1990 CAA amendments are considered, there is no ambiguity in Section 111(d) and the “literal interpretation” of the House amendment must be given full effect. As a result, EPA cannot use Section 111(d) to regulate existing fossil fuel-fired EGUs or any other source category that is subject to a Section 112 NESHAP.

2. The House Amendment to Section 111(d) Must Be Given Full Effect Because the Two Amendments Can Be Reconciled

Even if it were appropriate for EPA to assume now that despite being a drafting error, the Senate amendment must be incorporated into Section 111(d), that does not mean that the House amendment cannot be given full effect. Even when faced with two equally applicable provisions, full effect should be given to each to the extent possible. *See Watt v. Alaska*, 451 U.S. 259, 267 (1981). Here, EPA could give full effect to each provision by excluding from Section 111(d) any source category regulated under Section 112 *and* any pollutant listed in Section 112(b). By reading the two amendments in this light, EPA could give full effect to the plain meaning of each amendment in a manner consistent with Congress’ intent.

“When there are two acts upon the same subject, the rule is to give effect to both if possible.” *United States v. Borden Co.*, 308 U.S. 188, 198 (1939); *see also Watt*, 451 U.S. at 267 (an agency or court “must read [two allegedly conflicting] statutes to give effect to each if [it] can do so while preserving their sense and purpose”); *Morton v. Mancari*, 417 U.S. 353, 551 (1974) (“The courts are not at liberty to pick and choose among congressional enactments, and

when two statutes are capable of co-existence, it is the duty of the courts, absent a clearly expressed congressional intention to the contrary, to regard each as effective.”). Here, to the extent the Senate’s “drafting error” is to be given effect, the House amendment addressing the same subject—EPA’s authority to regulate existing sources under Section 111(d)—cannot be disregarded and EPA must give full effect to both provisions because both amendments “are capable of co-existence.”

While the House and Senate amendments do include differing language, as discussed above, they can be harmonized in a manner that gives full effect to each. Read literally, both the House and Senate amendments restrict EPA’s authority under Section 111(d) when stationary sources are already regulated through other more stringent sections of the CAA. The House amendment would prohibit EPA from regulating any pollutant—whether HAP or non-HAP—from a source regulated under Section 112, while the Senate amendment would prohibit EPA from regulating any HAP listed in Section 112. Thus, when read together, these two amendments are not in conflict, but, instead, can be fully reconciled by prohibiting EPA from regulating under Section 111(d) HAPs from any existing source *and* non-HAPs from source categories regulated under Section 112. Such an approach would be consistent with Congress’ intent to avoid duplicative regulation (or in the case of the Senate amendment, potential regulation) of existing sources under the CAA and give full effect to both the House and Senate amendments.

In contrast, as EPA readily admits, the Agency’s proffered interpretation fails to give full effect to either of the two amendments to Section 111(d). EPA first addressed this drafting anomaly in the preamble to the proposed Clean Air Mercury Rule and concluded that a “literal interpretation” of the House amendment to Section 111(d) would prevent EPA from regulating both HAP and non-HAP pollutants under Section 111(d) for sources that are subject to regulation under Section 112:

A literal reading of the House amendment, as contained in the Statutes at Large, is that a standard of performance under CAA Section 111(d) cannot be established for any air pollutant that is emitted from a source category regulated under Section 112. Under this reading, EPA could not regulate, under CAA Section 111(d), HAP and non-HAP emissions that are emitted from a source category regulated under Section 112. A literal reading of the Senate amendment is that a standard of performance under Section 111(d) cannot be established for any HAP that is listed in Section 112(b)(1), regardless of what categories of sources of that pollutant are regulated under Section 112.

69 Fed. Reg. 4651, 4685 (Jan. 30, 2004). However, rather than applying the “literal” meaning of the statute, EPA asserted that it had discretion to interpret Section 111(d) because the House and Senate amendments were in conflict. *Id.* (“The House and Senate amendments conflict in that they provide different standards as to the scope of EPA’s authority to regulate under Section 111(d).”). Rather than offering an interpretation that harmonizes the two amendments and gives full effect to both, EPA provided a narrow interpretation that only prohibited Section 111(d) regulations if both the pollutant *and* source category were subject to regulation under Section 112. Thus, contrary to Congress’ intent, EPA’s interpretation expands rather than limits the Agency’s authority to regulate existing sources under Section 111(d).

EPA has never disputed that this interpretation does not give full effect to the House amendment:

We recognize that our proposed reconciliation of the two conflicting amendments does not give full effect to the House's language, because a literal reading of the House language would mean that EPA could not regulate HAP or non-HAP emitted from a source category regulated under section 112. Such a reading would be inconsistent with the general thrust of the 1990 amendments, which, on balance, reflects Congress' desire to require EPA to regulate more substances, not to eliminate EPA's ability to regulate large categories of pollutants like non-HAP.

70 Fed. Reg. at 16,032.

This justification is nonsensical. There is no canon of statutory construction that permits an agency to ignore the plain meaning of a Congressional act because it does not think that Congress meant what it said. EPA cannot manufacture the need for discretion to interpret a statute by speculating about the "general thrust" of a broad and complex statutory scheme while ignoring the actual language adopted by Congress. This is particularly true when EPA is elevating a "drafting error" over a provision it concedes to be "substantive."

In this regard, no deference is owed EPA's views because *Chevron* does not apply to the issue of determining what law Congress actually enacted. *Accord, Am. Bar Ass'n*, 430 F.3d at 469 (*Chevron* is only applicable where there has been a "delegation of authority to the agency") (citing and quoting *Sea-Land Serv., Inc. v. DOT*, 137 F.3d 640, 645 (D.C. Cir. 1998)). And here, it is undisputed that the House amendment forbids EPA from using Section 111(d) to regulate source categories that are already subject to regulation under Section 112, and nothing in the Senate amendment precludes EPA from giving full effect to the House Amendment.

3. The House Amendment Is Consistent with the Co-benefits Associated with Regulating Sources Under Section 112

It is clear as a policy matter that Congress, in the 1990 CAA amendments, was focused on avoiding unnecessary and duplicative regulation of emissions from stationary sources. As EPA has recognized, this is particularly true for EGUs. *See* 70 Fed. Reg. at 15,999 (asserting that Congress' treatment of EGUs "reveals Congress' recognition that Utility Units are a broad, diverse source category that is subject to numerous CAA requirements, including requirements under both Title I and Title IV, *and that such sources should not be subject to duplicative or otherwise inefficient regulation*"). Prohibiting EPA from regulating existing sources under both Sections 111(d) and 112 is consistent with the broader policy objective of avoiding duplicative regulation. Emission controls designed to reduce emissions of one pollutant typically have the effect of reducing emissions of a much broader suite of pollutants. Thus, when EPA requires a facility to install the maximum achievable control technology ("MACT") required under Section 112 to reduce target pollutants, there can frequently be little or no need for additional regulatory obligations for other pollutants under section 111(d) because applying the stringent MACT standard can have the effect of controlling many other common pollutants.

The concept of the “co-benefits” associated with emissions controls is well-established. For example, in the MATS rulemaking, EPA explained that reducing HAP emissions from EGUs would also reduce emissions of PM_{2.5} and SO₂ and went to great lengths to monetize the projected health benefits associated with reducing PM_{2.5} emissions. 77 Fed. Reg. at 9428-32. Likewise, when setting Section 112 standards for cement kilns and industrial, commercial and institutional boilers, EPA has explained that “setting technology-based standards for HCl will result in significant reductions of other pollutants including SO₂, Hg, and PM.” 76 Fed. Reg. 15,608, 15,643 (Mar. 21, 2011). Indeed, even in this proposal, EPA relies heavily on the co-benefits associated with projected reductions in PM_{2.5}, SO₂, and NO_x emissions. 79 Fed. Reg. at 34,937, t.14.

The correlation between emission reductions of multiple pollutants is also central to EPA’s practice of using surrogates as a means of controlling emissions of hazardous air pollutants. Under this approach, “EPA may regulate [a] pollutant indirectly when its emissions are controllable by regulation of other pollutants.” *Nat’l Lime Ass’n v. EPA*, 233 F.3d 625, 637 (D.C. Cir. 2000) (citing *NRDC v. EPA*, 822 F.2d 104, 125 (D.C. Cir. 1987)). Thus, with respect to Section 112, courts have held that “EPA may use a surrogate to regulate hazardous air pollutants if it is ‘reasonable’ to do so,” and have repeatedly held that EPA can use non-HAP criteria pollutants such as PM_{2.5} as surrogates for HAP pollutants under Section 112. *Id.* at 637-40; *Sierra Club v. EPA*, 353 F.3d 976, 984 (D.C. Cir. 2004). EPA’s frequent reliance on co-benefits and surrogates under Section 112 is consistent with policy underlying Congress’ decision to foreclose regulation under Section 111(d) where a source category is regulated under Section 112—regulation of hazardous air pollutants from a source category under Section 112 can have the ancillary effect of reducing emissions of other non-HAP pollutants that might otherwise be regulated under Section 111(d).³⁶

C. Policy Considerations Also Require Giving Section 111(d) Its Plain Meaning In The Context of GHG Emissions

Beyond the legal interpretation, there are also compelling policy reasons for EPA to give full effect to the House amendment in this rulemaking to avoid regulating GHG emissions from source categories that are already subject to Section 112 NESHAPs. Controlling GHG emissions from existing sources is fundamentally different from the regulation of GHG emissions from new sources, as well as from other pollutants from existing sources.

³⁶ Congress’ decision to forbid additional regulation of Section 112 sources is also supported by the fact the preemption applies only to existing sources. Retrofitting existing sources with new pollution control technology is extremely costly and will provide limited benefits since, in many cases, existing sources have a limited remaining useful life. In contrast, new sources, which have more flexibility to install pollution controls and longer projected useful lives, can be subject to both Section 112 MACT standards and standards of performance under Section 111(b). Likewise, existing sources that are regulated under Section 112 and elect to undergo a modification or reconstruction can also be subject to standards of performance under Section 111(b).

First, regulation of existing sources already subject to Section 112 would add an additional layer of regulatory complexity to industries that can ill afford it. Existing sources subject to NESHAPs issued pursuant to Section 112 already must apply the stringent MACT standard to reduce HAP emissions, making it among the most stringent CAA provisions. Congress did not intend that existing sources already subject to these stringent MACT standards should also be subject to additional regulatory burdens associated with the Section 111 NSPS program. Such an approach would threaten to cripple these important industries, which are already struggling to comply with many recently issued or amended NESHAP standards.³⁷

EPA's proposal here effectively turns the CAA regulatory structure on its head and makes Section 111(d) a more impactful, stringent, expansive, and onerous program than Section 112. Contrary to Congress' intent, EPA has proposed to use Section 111(d) to exercise complete authority over the electricity sector—including the authority to dictate the fuel mix and energy efficiency of existing power plants. In addition to mandating significant and expensive heat rate improvements at existing coal-fired power plants, EPA's proposal would have the effect of forcing the retirement of a significant portion of current coal-fired generating capacity and replacing it with other forms of generation.³⁸ Such a shift in electricity generation raises serious issues related to infrastructure needs, and grid reliability, as demonstrated by the recent NERC report. *See* Section I., *supra*. Further, an analysis of existing Section 111(d) regulations demonstrates that they are not well-suited to sweeping regulation of broad-based emissions such as CO₂. Martineau, *The Clean Air Act Handbook* 308 (2d ed. 2004) (assessment of EPA's current Section 111(d) guidelines suggests that they are “developed for specialized types of emissions sources that emit discrete types of pollutants”). By using Section 111(d) as a means to regulate the entire electricity sector, EPA would shift Section 111(d) from a seldom-used backstop provision to the central and preeminent CAA provision for regulating air pollution—the very type of regulatory over-reach foreclosed by *UARG*.

Second, by regulating GHG emissions from existing fossil fuel-fired power plants under Section 111(d), EPA would open the door to particularly adverse impacts for other sources that

³⁷ For example, EPA projected that the MATS rule would impose \$9.6 billion in compliance costs on power plants. *See* EPA Fact Sheet: Mercury and Air Toxics Standards: Benefits and Costs of Cleaning Up Toxic Air Pollution from Power Plants, *available at* <http://www.epa.gov/mats/pdfs/20111221MATSimactsfs.pdf>. Industry estimates of compliance costs have been much higher, and many facilities have been forced to close after concluding that complying with MATS will be too costly. *See, e.g.*, Press Release, Duke Energy, W.C. Beckjord Station Retirement Plans (announcing retirement of coal-fired EGUs because EPA “is expected to soon implement environmental regulations that would require cost-prohibitive equipment upgrades and retrofits to the plant”).

³⁸ EPA projects that the proposed rule will reduce electricity generation from coal by 26%. *See* EPA, Data File: Goal Computation –Appendix 1 and 2, *available at* <http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-technical-documents>. More importantly, EPA projects that by 2020 an additional 49 MW GW of coal generating capacity—representing 19% of the current coal generation fleet—will be retired beyond what would occur in the absence of the rule. EPA, RIA at 3-32.

are trade exposed. As explained in Section XVI., *infra*, many of the manufacturing and industrial sectors subject to Section 112 NESHAPs are trade exposed. These energy-intensive industries operate with very small margins and face stiff competition from facilities in other nations where there are often no GHG or HAP controls. Even small increases in electricity and natural gas feedstock costs—or direct compliance costs from industry-specific existing source rules—can adversely affect the competitiveness (and market share) of domestic facilities in comparison to overseas competition where GHGs and other pollutants may be emitted without any controls at all. Thus, imposing strict GHG emissions limits on existing sources under Section 111(d) could have perverse effects on global GHG emissions through overseas leakage. Indeed, EPA has conducted no analysis as to whether the proposed rule could lead to even greater GHG emissions by shifting manufacturing overseas to countries that have much more GHG-intensive energy generation. Barring Section 111(d) regulations for existing sources subject to Section 112 will help alleviate some of the burdens of the U.S. regulatory system on trade exposed industries, reduce the risk of overseas emissions leakage, and help ensure that domestic industries remain competitive in the global marketplace. In contrast, subjecting trade exposed sectors to higher electricity and natural gas costs and preserving the threat of potential future regulation of existing sources will create significant uncertainty that will influence companies’ decisions to build and operate facilities in the United States.

Third, applying Section 111(d) to these source categories will impose unprecedented burdens on State permitting agencies given the large number of existing sources. The Section 111(d) program would be implemented primarily by the States, which would have to address all covered sources within their jurisdiction. This would be a significant undertaking, as EPA envisions that States will adopt a “portfolio approach” that extends far beyond the regulated source categories. Indeed, in addition to regulating existing fossil fuel-fired EGUs, States will be obligated to develop implementation plans that address the entire electricity sector, including renewable energy, nuclear energy, and even consumer choices through demand-side energy efficiency programs. By doing so, EPA would effectively be commandeering States programs such as RPSs and EERSs that are based on traditional powers exercised by the States. It is fundamentally inconsistent with the principles of cooperative federalism on which the CAA is based—as well as the Tenth Amendment—for EPA to effectively mandate the manner in which States exercise their own authority. *See* Sections VI.B.-C., *infra*. Even putting this aside, as EPA is well aware, State permitting agencies are already struggling under the administrative burdens of existing federal programs including GHG permitting programs, NESHAPs, and revised NAAQS and, in many cases, the agencies lack the capacity and resources to implement an additional complex and expansive permitting program such as that envisioned by EPA in the proposed Section 111(d) standards. It would be irresponsible for EPA to impose such a regulatory burden on the States, particularly without a clear mandate from Congress to do so.

IV. EPA MUST MAKE A SEPARATE SIGNIFICANT CONTRIBUTION ENDANGERMENT DETERMINATION BASED ON CO₂ EMISSIONS FROM EACH SOURCE CATEGORY

Section 111 requires EPA to make a determination that pollutants from the source category that it seeks to regulate “cause[], or contribute[] significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare,” 42 U.S.C. § 7411(b)(1)(A). In the January 2014 Section 111(d) proposal for newly constructed sources, 79 Fed. Reg. 1,430

(Jan. 8, 2014), EPA claimed that such a determination was unnecessary for regulating GHG emissions from fossil fuel-fired EGUs. Instead, EPA asserted that because it had already made an endangerment determination for a different pollutant emitted by fossil fuel-fired EGUs, it only needed to provide a “rational basis” for expanding the NSPS program to encompass entirely new pollutants. 79 Fed. Reg. at 1454; *see also* 79 Fed. Reg. at 34,978. This is unlawful. The plain language of Section 111 requires EPA to make a significant contribution endangerment determination that is specific to the source category and pollutant that it seeks to regulate. It has done neither here. Moreover, even if Section 111 were ambiguous, EPA cannot substitute an admittedly less stringent threshold for regulation by applying a rational basis test in lieu of the statutorily mandated endangerment determination.

A. Section 111 Requires Both A Source- And Pollutant-Specific Endangerment Determination

Under the Clean Air Act, EPA must make both a source- *and* pollutant-specific endangerment determination before issuing standards of performance under Section 111(b). Further, because EPA must establish valid standards of performance under Section 111(b) before it can regulate existing sources from the same source category under Section 111(d), this threshold requirement applies equally to Section 111(d) rulemakings. Therefore, unless EPA makes a specific determination that (1) CO₂ emissions (2) from coal- and natural gas-fired EGUs (3) “cause[], or contribute[] significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare,” 42 U.S.C. § 7411(b)(1)(A), it cannot proceed with any of the proposed GHG NSPS rules.

Although EPA has finalized an endangerment determination for GHG emissions from cars and light duty trucks under Section 202(a), that pollutant-based determination is not germane to Section 111’s distinct legal standard. As EPA has acknowledged, unlike Section 202(a), Section 111 requires a specific determination of endangerment from fossil fuel-fired EGUs and a specific determination that emissions from such sources comprise a significant contribution to endangerment. *See* 74 Fed. Reg. 66,496, 66507 (Dec. 15, 2009) (“[T]he statutory language in CAA section 202(a) does not contain a modifier on its use of the term contribute. Unlike other CAA provisions, it does not require a ‘significant’ contribution. *See, e.g.,* CAA section 111(b); 2013(a)(2), (4).”). Nor can EPA rely on past endangerment determinations under Section 111(b)(1)(A) because they were based on different pollutants (and potentially different sources) than those addressed in the proposed rule. *See* 36 Fed. Reg. 5931 (Mar. 31, 1971) (making significant contribution endangerment determination for all “fossil fuel-fired steam generators of more than 250 million B.t.u. per hour heat input”).

The endangerment determination in Section 111(b)(1)(A) is fundamentally different than that in Section 202(a) and other Clean Air Act provisions, in part because it: (1) is source-category based; and (2) requires a finding of significance. Under Section 111(b)(1)(A) EPA is only permitted to regulate “*a category of sources ... if in his judgment it causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.*” (emphasis added). In contrast, other sections broadly include all emissions sources for a given pollutant, authorizing the Administrator to regulate emissions “which in his judgment cause, or contribute to, air pollution which may reasonably be anticipated to endanger public health or welfare.” 42 U.S.C. § 7521(a)(1); *see also id.* § 7408(a)(1)(A). Thus, Section

111(b)(1)(A) is more demanding than other provisions of the Clean Air Act and requires EPA to make an endangerment determination that is not only specific to each source category and pollutant that EPA seeks to regulate, but also based on a higher “significance” threshold.

B. EPA Cannot Substitute The Statutory Requirements Of Section 111(b)(1)(A) With A “Rational Basis” Test

Rather than satisfying the plain requirement of Section 111 and proposing to make a CO₂-specific endangerment finding of significant contribution for fossil-fuel fired EGUs, EPA asserted in the January 2014 Section 111(b) proposal that, once it has made an initial endangerment determination for a source category for any pollutant, it need only offer a rational basis for regulating additional pollutants, including CO₂, regardless of the lack of any relationship that the newly regulated pollutant has to the initial endangerment determination. *See* 79 Fed. Reg. at 1454. EPA then points to the findings it made under a different Title of the CAA (Title II) as providing the required “rational basis” for the endangerment finding for CO₂. While EPA did not specifically address its proposed “rational basis” test for satisfying the significant contribution endangerment determination found in Section 111(b), that interpretation is nonetheless germane to this rulemaking because EPA cannot regulate a pollutant from existing sources in a source category under Section 111(d) unless it first makes a legally justifiable endangerment determination for the pollutant and source category in association with establishing standards of performance under Section 111(b). As explained below, EPA’s interpretation of the significant contribution endangerment determination in the proposed Section 111(b) rule fails for three reasons.

First, EPA is incorrect in asserting that Section 111(b)(1)(A) is ambiguous and that EPA is authorized to fill a purported statutory gap regarding the content of the endangerment finding. The plain language of Section 111(b)(1)(A) establishes that the purpose of the NSPS program is to regulate and reduce emissions that “significantly contribute” to “air pollution” that “endanger public health or welfare.”³⁹ EPA’s proposed interpretation would divorce the endangerment determination from the subject of regulation and would fail to provide any assurance that the regulations would serve to mitigate emissions that “contribute significantly” to public health

³⁹ As explained above, NSPS presents a unique requirement in that EPA’s endangerment finding must be both source- and pollutant-specific. EPA’s reliance on the pollutant-specific endangerment determination requirements in Sections 211 and 231 is inapposite, as those provisions only apply to specific source categories: motor vehicles and engines, and aircraft. The fact that the NSPS provisions require a separate endangerment determination for each source category compels the conclusion that EPA must also assess the pollutant to be regulated under NSPS for each source category and cannot simply incorporate an endangerment determination for a pollutant under an entirely distinct Clean Air Act provision. This is further underscored by the fact that the “endangerment” determinations made under sections 211 and 231 did not require a finding that the emissions “significantly contribute” to endangerment, but only the much lower standard that there was some “contribution.”

concerns.⁴⁰ This interpretation of Section 111(b)(1)(A) would irrationally and arbitrarily allow EPA to impose standards of performance for air pollutants emitted from a source category that do not “contribute significantly” to an endangerment of public health or welfare. Thus, under the plain language of Section 111(b)(1)(A), a pollution-specific endangerment requirement and significance determination is the check Congress provided to ensure that EPA does not issue costly (and ultimately ineffective) regulations for air pollutants that need not be regulated for a particular source category under Section 111.

Applying this standard, there is no question that CO₂ emissions fall outside of the prior endangerment determinations and significance findings that EPA made under NSPS Subparts Da and KKKK. *See, e.g.*, 36 Fed. Reg. 5931. EPA’s prior NSPS endangerment findings were all made before the Supreme Court decided, in *Massachusetts v. EPA*, 549 U.S. 497 (2007), that GHGs were “air pollutants” under the Clean Air Act. Until that time, EPA did not consider GHGs—including CO₂—to be potentially subject to regulation as “air pollutants.” *Id.* at 511-12. Thus, there is no question that EPA has neither made a Section 111(b)(1)(A) endangerment determination nor a finding of significance for these source categories that could cover GHGs, or, more specifically, CO₂, the pollutant EPA seeks to regulate here.⁴¹

Second, assuming *arguendo* that the statute is ambiguous, EPA’s interpretation is unreasonable and, therefore, not entitled to deference under *Chevron*. *See, e.g., Bluewater Network v. EPA*, 370 F.3d 11 (D.C. Cir. 2004). In the January 2014 Section 111(b) proposal, EPA asserted that it can demonstrate a rational basis for regulating a pollutant “based on information concerning the health and welfare impacts of the air pollution at issue, and the amount of contribution that the source category’s emission make to that air pollution.” 79 Fed. Reg. at 1454. This interpretation ignores the statutory text, which requires a finding of “significance” and, instead, would admittedly apply a lower and wholly subjective standard than the statutory mandate. An interpretation that vaguely references “information concerning health and welfare impacts” and “the amount of contribution” of a source category’s emissions is so far removed from the statute’s significance requirement that it is patently unreasonable and cannot be entitled to *Chevron* deference.

Nor can EPA save its interpretation by citing the rational basis standard that the D.C. Circuit has previously applied to NSPS endangerment determinations. *See id.* at 1455 (citing

⁴⁰ EPA cannot salvage this interpretation by simply making a new GHG-specific finding of significance for the new source category. In any event, as discussed below, EPA’s proposed finding of significance is arbitrary and capricious as it lacks any rational basis whatsoever.

⁴¹ As an alternative to adding standards of performance for GHG emissions under subparts Da and KKKK, EPA proposes to create a new subcategory TTTT for all fossil fuel EGUs. *See* proposed 40 C.F.R. subpart TTTT. However, under Section 111(b)(1)(A) the Administrator is only permitted to regulate “a category of sources ... if in his judgment it causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.” (emphasis added). EPA has not made such a finding with respect to GHGs or any other pollutants for this newly proposed source category and thus is legally barred from establishing a standard of performance for GHG emissions under this alternative proposal.

Nat'l Lime Ass'n v. EPA, 627 F.2d 416 (D.C. Cir. 1980) and *Nat'l Asphalt Pavement Ass'n v. Train*, 539 F.2d 775 (D.C. Cir. 1976)). Each of those cases involved challenges to EPA's specific endangerment determination for the pollutant and source category it sought to regulate—the very action EPA neglected to undertake in this rulemaking. The fact that the D.C. Circuit reviewed those endangerment determinations under a rational basis standard of judicial review offers no support for EPA's assertion here that it can satisfy the statutorily-required endangerment determination by offering a “rational basis” for failing to make that determination before imposing standards of performance for GHG emissions. In fact, EPA cites no prior example of an NSPS standard where anything less than a source- and pollutant-specific determination was required.

Third, even if EPA could apply a rational basis approach to the significant contribution endangerment determination, the use of that approach for the proposed Section 111(b) rule for GHG emissions from coal-fired EGUs, and thus in this proposal, is arbitrary because EPA fails to establish that the rule will have any effect on reducing the emissions that it deems significant. EPA's assertion that “a single new coal-fired power plant may amount to millions of tons [of CO₂] each year,” 79 Fed. Reg. at 1455, does not provide a rational basis for making endangerment and significance findings for issuing a GHG NSPS for coal-fired EGUs. Nor does EPA's assertion that “fossil fuel-fired EGUs are the nation's largest source of carbon pollution.” *Id.* at 1433. EPA must also show that its regulations will reduce emissions and that the reduction will ameliorate the endangerment. EPA failed to do so in the proposed Section 111(b) rule. There, EPA asserted that the rule would have no effect at all on CO₂ emissions because no new coal-fired EGUs will be constructed anyway. *Id.* at 1433 (“EPA projects that the rule will result in negligible CO₂ emission changes”); *see also* EPA, Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants, 5-1 – 2 (June 2014) (“RIA”).⁴² In addition, EPA's rulemaking authority is limited to “prescrib[ing] such regulations as are necessary to carry out” the Administrator's functions under the CAA. 42 U.S.C. § 7601(a). A rule that will have no effect on air emissions and that produces no benefits of any kind cannot be considered “necessary” under any interpretation of the CAA.

Further, under the rationale advanced by EPA, the proposed NSPS regulations appear to violate Executive Order 13563, which requires agencies to promote coordination, simplification and harmonization of rulemakings to avoid redundant, unnecessary, inconsistent, or overlapping regulation. If, as EPA asserts, economic drivers are genuinely preventing the construction of new coal-fired EGUs, then the Agency's proposed Section 111(b) rule for newly constructed sources is an unnecessary regulation under the Executive Order. Thus, EPA's application of its rational basis approach in the Section 111(b) proposal is clearly arbitrary, capricious, and not in

⁴² The steep emission reductions that EPA is proposing in the Section 111(d) rule cannot cure this defect in the Section 111(b) proposal. Because EPA is not obligated to—and, in some cases, is prohibited from—regulating existing sources under Section 111(d), the endangerment determination must focus solely on emission reductions from new sources. Further, as explained in Section VII., *infra*, EPA is not permitted to look beyond the fence line when establishing emissions guidelines and, as a result, the emission reductions associated with regulating existing sources under Section 111(d) will ultimately be much more limited than what EPA projects here.

accordance with the law. Further, EPA's proposed rule for existing sources would also be arbitrary, capricious, and unlawful because the regulation of new sources under Section 111(b) is a prerequisite for the regulation of existing sources under Section 111(d).

C. EPA's "Rational Basis" Does Not Constitute The Endangerment And Significance Determination Required By Section 111(b)

As an alternative, EPA asserted in the January 2014 Section 111(b) proposal that even if pollutant-specific endangerment and significance findings are required, "our rational basis, as described, should be considered to constitute those findings." 79 Fed. Reg. at 1455-56. As an initial matter, after taking great pains to argue it did not need to make a statutory endangerment and significance finding, EPA cannot claim that its rational basis approach nevertheless satisfies the endangerment and significance criteria. In any event, EPA's rational basis would fail because EPA cannot satisfy the requirements of Section 111(b)(1)(A) by importing from another section of the Clean Air Act a *general* endangerment determination for an entire suite of GHGs from a different source of emissions.⁴³

First, the language of Section 111(b)(1)(A) is clear and requires EPA to make an endangerment determination that is (1) source-specific and (2) includes a significance finding relative to the "air pollution" at issue. EPA's rational basis approach relies primarily on the generalized Section 202(a) endangerment determination and denials of petitions for reconsideration, 79 Fed. Reg. at 1455, 56, which do not address Section 111's distinct significance threshold. EPA's Section 202(a) determination did not address EGUs and did not address the significance threshold. 74 Fed. Reg. 66,496, 66,507 (Dec. 15, 2009) ("Moreover, the statutory language in CAA section 202(a) does not contain a modifier on its use of the term contribute. Unlike other CAA provisions, it does not require a 'significant' contribution. See, e.g., CAA section 111(b); 2013(a)(2), (4)."). Thus, EPA fails to give meaning to the plain language of Section 111(b)(1)(A) and instead simply reads these key requirements out of the statute. "[N]o deference is due to agency interpretations at odds with the plain language of the statute itself." *Ohio Pub. Emps Ret. Sys. v. Betts* 492 U.S. 158, 171 (1989)); see also *Duncan v. Walker*, 533 U.S. 167, 174 (2001). Thus, EPA cannot simply gloss over Congress' decision to use different language for different endangerment determinations by importing an endangerment determination from one CAA section to another.

Second, EPA arbitrarily failed to identify or apply any reasoned standard for its proposed finding that CO₂ emissions from the new source category "cause or contribute significantly to the GHG air pollution." 79 Fed. Reg. at 1456. Instead, EPA asserts without basis "that it is not necessary for EPA to decide whether it must identify a specific threshold for the amount of emissions from a source category that constitutes a significant contribution." *Id.* EPA says it

⁴³ EPA failed to address the inconsistency between the scope of the Section 202(a) endangerment finding, which included CO₂, nitrous oxide, and other GHGs, and the proposed rule here, which only applies to CO₂. While EPA suggested that the emissions of nitrous oxide and methane from the new source category are insignificant, 79 Fed. Reg. at 1,455, it failed to address the fact that these emissions played an important role in EPA's endangerment determination under Section 202(a).

can assume emissions from fossil fuel-fired EGUs make “significant contributions” because they are “the largest single stationary source category of GHG emissions.” *Id.*

EPA is now relying on the prior findings it made under Section 202(a) which found that nationwide GHG emissions threatened to “endanger” the public health and welfare. 74 Fed. Reg. 66,496. EPA is thus reasoning that because GHG emissions from EGUs constitute a significant percentage of overall GHG emissions, those EGU emissions must “significantly contribute” to air pollution that may endanger the public health and welfare. But, as a matter of simple math, the fact that nationwide emissions may contribute to endangerment does not demonstrate that some *lesser* amount of emissions contribute *significantly* to endangerment. Rather, EPA would need to establish a standard of “significance” to establish that the lesser emissions “significantly contribute” to endangerment. Here, however, EPA has failed to articulate any standard for determining significance that would allow it to then establish that a source category’s emissions exceed that significance threshold. *See Motor Vehicle Mfrs. Ass’n v. State Farm Mut. Auto. Ins. Co.* 463 U.S. 29, 43 (1983) (an agency must provide a reasoned basis for its actions); *Int’l Union, UAW v. NLRB*, 514 F.3d 574, 583 (6th Cir. 2008) (agency may not engage in “illogical or arbitrary” line drawing). While EPA may not have to specify a strict numerical threshold, it must still articulate some standard for determining whether a particular level of emissions are “significant” or “insignificant”—simply asserting “we know it when we see it” does not satisfy the requirements of reasoned decision making imposed on federal agencies. *See, e.g., United States Telecom Ass’n v. FCC*, 188 F.3d 521, 526 (D.C. Cir. 1999).

Finally, even if it were to make an endangerment and significance finding for GHG emissions from the new source category here, EPA would also have to establish that its proposed Section 111(b) rule could meaningfully address the significant endangerment. *Cf. e.g., Ethyl Corp. v. EPA*, 541 F.2d 1, 31 & n.62 (D.C. Cir. 1976) (EPA must be able to show that a regulation issued in light of a Section 202(a) endangerment determination is capable of meaningfully and substantially reducing the extent of identified danger). EPA’s own analysis suggests that the proposed standards of performance under Section 111(b) will not reduce total GHG emissions from new fossil fuel-fired EGUs. 79 Fed. Reg. at 1433 (projecting that no new coal-fired EGUs will be constructed by 2030). Further, with respect to existing facilities, EPA cannot focus solely on reducing domestic emissions while ignoring leakage effects, particularly when it addresses global pollutants such as GHGs. Coal and other solid fuels are international commodities, and a mandated reduction in domestic demand will simply lower prices and increase consumption in other countries with less stringent standards. Moreover, increasing electricity prices domestically will harm energy intensive, trade exposed industries and may shift production overseas where GHG emissions—as well as those of conventional pollutants—may not be subject to controls. Thus, a *de facto* ban on coal usage for new, domestic power generation (which is what the proposed 111(b) rule effectively contemplates) and a forced reduction in generation from existing coal-fired EGUs will merely shift the location of emissions; it will not eliminate them. At the same time, increased consumption abroad will also increase emissions of other criteria pollutants, some of which are already causing increases in background concentrations domestically.

V. EPA’S DEPARTURES FROM THE PROPOSED SECTION 111(b) RULE TO DEFINE STANDARDS UNDER SECTION 111(d) ARE UNLAWFUL

A. EPA’s Regulation Of Existing Sources Under Section 111(d) Is Inextricably Tied To Its Regulation Of New Sources Under Section 111(b)

Because of the inextricable ties between the regulation of new and existing sources under Sections 111(b) and 111(d), the standards of performance that are established for existing sources under Section 111(d) must be informed by, related to, and consistent with the standards established for new sources under Section 111(b). *UARG*, 134 S. Ct. at 2442 (“[R]easonable statutory interpretation must account for both ‘the specific context in which ... language is used’ and the broader context of the statute as a whole.” *Robinson v. Shell Oil Co.*, 519 U. S. 337, 341 (1997).”). Here, instead, EPA has proposed two entirely distinct, independent, and inconsistent regimes under separate subsections of the same Clean Air Act provision that are designed to work in tandem.

The structure and content of Section 111 makes clear that the standards of performance for new and existing sources must be interpreted and applied in a consistent manner. At the same time, Section 111 does not require identical regulation and instead provides flexibility under Section 111(d) to consider additional factors that are not relevant for new sources. Thus, while the standards of performance and BSER analysis applied to new sources under Section 111(b) serve as the starting point for regulation of existing sources under Section 111(d), the States and EPA have flexibility to impose less stringent standards of performance that reflect unique challenges associated with retrofitting existing sources with pollution controls. However, the Section 111(b) standards for new sources clearly provide the ceiling on what EPA may impose under Section 111(d) for existing sources. Because EPA’s interpretation is “inconsistent with the design and structure of” the CAA, it “does not merit deference.” *Id.* (citing *United Sav. Ass’n of Tex. v. Timbers of Inwood Forest Assocs, Ltd.*, 484 U. S. 365, 371 (1988)).

First, the structure of Section 111 makes clear that the regulation of existing sources under Section 111(d) was intended to be consistent with and related to the regulation of new sources from the same source category under Section 111(b) and, therefore, the standards of performance for new and existing sources must be established using consistent methodologies. Under Section 111(d), the regulation of new sources under Section 111(b) is a necessary prerequisite for regulation of existing sources from the same source category under Section 111(d). *See* 42 U.S.C. § 7411 (standards of performance may only be established for an existing source “to which a standard of performance would apply if such existing source were a new source”). By making regulation of existing sources contingent upon the promulgation of standards of performance for new sources, Congress showed a clear intent to make Section 111(d) a supplementary program that complements and is informed by the standards of performance and BSER analysis applied to new sources.

This inextricable link between Sections 111(b) and 111(d) is fully consistent with traditional canons of statutory construction. The Supreme Court has repeatedly recognized “the ‘normal rule of statutory construction’ that ‘identical words used in different parts of the same act are intended to have the same meaning.’” *Gustafson v. Alloyd Co.*, 513 U.S. 561, 570 (1995)

(quoting *Dep't of Revenue of Ore. v. ACF Indus., Inc.*, 510 U.S. 332, 342 (1994)). This canon applies most clearly when multiple provisions cross reference the same term or phrase. As the Supreme Court explained, “[w]e have even stronger cause to construe a *single* formulation, here § 5322(a), the same way each time it is called into play.” *Retzlaf v. United States*, 510 U.S. 135, 143 (1994). Here, there is little question that the “standards of performance” referenced in Sections 111(b) and (d) are to be established using the same BSER analysis. Not only did Congress use identical language directing EPA and the States to establish standards of performance for new and existing sources respectively, each of these provisions looks to *the same definition* of “standard of performance” in Section 111(a). By defining “standard of performance” in the same section of the statute that applied it, Congress was clearly directing EPA to apply a single definition of that term.

Thus, because they cross reference the same definition of “standard of performance,” when EPA seeks to regulate the same air pollutant from the same source category under Sections 111(b) and (d), it must apply the same methodology when conducting the BSER analysis on which the standards of performance are based. The necessity of applying the same methodology is further underscored by the internal cross references that ties the establishment of standards of performance for existing sources to EPA’s standard of performance for new sources in the same source category. 42 U.S.C. § 7411(b). EPA recognized the need to rely on the same methodology for new and existing sources in the past when it promulgated implementing regulations for Section 111(d), stating, “the general principle (application of best adequately demonstrated control technology, considering costs) will be the same in both cases.” 40 Fed. Reg. 53,340, 53,341 (Nov. 17, 1975).

EPA has further explained in other Section 111(d) rulemakings that the legislative history of Section 111(b) underscores Congress’ intent that these provisions be applied in the same manner. The provision which is now Section 111(d) was originally approved by the Senate as a stand-alone provision, Section 114. *Id.* at 53,342. However, the Committee of the Conference moved that provision to Section 111(d). EPA explained that this decision was significant and “reflected a decision in conference that a similar approach [to that applied to new sources] (making allowances for the costs of controlling existing sources) was appropriate for the pollutants to be controlled under section 111(d).” *Id.* Thus, there is no question that the BSER analysis used to establish standards of performance for new sources must serve as the starting point for establishing standards of performance for existing sources from the same source category.

Second, while the same principle or methodology must be applied in both cases, standards of performance established under Section 111(b) provide the ceiling for the Section 111(d) standards, which, in turn, are more flexible and must take into account challenges associated with retrofitting existing facilities with pollution controls. Again, while the cross reference in Section 111(d)(1) looks to EPA’s establishment of standards of performance of new sources in a given source category as the starting point for regulating existing sources under Section 111(d), EPA and the States are directed to “tak[e] into account the cost of achieving” emission reductions as a part of the BSER analysis. 42 U.S.C. § 7411(a). Thus, as EPA has recognized, certain control technologies that may be economically feasible for new facilities may be deemed too costly for existing facilities due to the inevitable cost increases associated with retrofitting a facility that was originally designed without the specific control technology in

mind. *See* 40 Fed. Reg. at 53,344 (“Such a consideration [of cost] is inherently different than for new sources because controls cannot be included in the design of an existing facility and because physical limitations may make installation of particular control systems impossible or unreasonably expensive in some cases.”). Comparing the process for applying BSER to new and existing facilities, EPA stated:

[T]he regulations have been amended to make clear that the Administrator will specify different emission guidelines for different size, types, and classes of designated facilities when costs of control, physical limitations, geographical location, and similar factors make subcategorization appropriate [§ 60.22(b)(5)]. Thus, while there may be only one standard of performance for new sources of designated pollutants, there may be several emissions guidelines specified for designated facilities based on plant configuration, size, and other factors peculiar to existing facilities.

40 Fed. Reg. at 53,341. Thus, even though the BSER analysis used for new sources under Section 111(b) must serve as the starting point under Section 111(d), the consideration of costs affords additional flexibility to establish less stringent standards of performance for existing sources.

Congress, in enacting Section 111(d), went further and specifically directed States (and EPA under federal implementation plans) to “take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies.” *Id.* § 7411(d)(1)-(2). Thus, while the same principle or methodology applies, States are given additional flexibility under Section 111(d) to establish standards of performance for existing sources in a source-specific context. Indeed, EPA’s own implementing regulations state:

Unless otherwise specified in the applicable subpart on a case-by-case basis for particular designated facilities or classes of facilities, States may provide for the application of less stringent emissions standards or longer compliance schedules than those otherwise required by paragraph (c) of this section, provided that the State demonstrates with respect to each such facility (or class of facilities):

- (1) Unreasonable cost of control resulting from plant age, location, or basic process design;
- (2) Physical impossibility of installing necessary control equipment; or
- (3) Other factors specific to the facility (or class of facilities) that make application of a less stringent standard or final compliance time significantly more reasonable.

40 C.F.R. § 60.24(f).

Third, the clear implication of this statutory approach is that the standards of performance established for existing sources cannot be more stringent than those established for new sources and will usually be less stringent. The statute provides only additional flexibility for existing sources, not criteria for imposing more stringent standards. And in practice, if the same BSER

analysis is applied to new and existing sources in a given source category, it is virtually impossible that EPA or the States would conclude that any system of emission reduction that is adequately demonstrated for existing sources cannot be implemented by new sources. Instead, regulators are likely to find that, due to retrofitting costs or design constraints, certain pollution control technologies that are available for new sources cannot be installed in some or all existing sources. As EPA explained when it promulgated implementing regulations for Section 111(d), “the degree of control reflected in EPA’s emission guidelines will take into account the costs of retrofitting existing facilities and thus will probably be less stringent than corresponding standards for new sources.” 40 Fed. Reg. 53,340.

EPA’s historic application of Section 111(d) exemplifies this point. For example, with respect to emissions of sulfuric acid mist from new sulfuric acid plants, EPA concluded that the installation of vertical tube mist eliminators would allow new sources to meet a standard of performance of 0.075 g/Kg. 41 Fed. Reg. 48,706, 48,706 (Nov. 4, 1976). For existing sources, however, EPA set a higher emission guideline of 0.25 g/Kg based on a more general class of fiber mist eliminators. *Id.* First, EPA found that certain existing sources—those burning bound sulfur feedstocks or producing strong oleum products—could not meet the 0.075 g/Kg standard, even if vertical tube mist eliminators were installed. In other cases, EPA found that sources had already been required to install horizontal dual pad or vertical pad type mist eliminators and concluded that requiring double retrofitting to vertical tube mist eliminators “would cause an adverse economic impact to the industry.” *Id.* Thus, although EPA applied the same BSER analysis to new and existing facilities and used the systems of emission reduction identified for new sources as a starting point, it relied on the flexibility provided by Section 111(d) to select a less stringent standard for existing sources.

Taken together, these points highlight the fact that Sections 111(b) and 111(d) are designed to operate in tandem, with the same analytical approach applied to evaluate the same systems of emission reduction for new and existing sources in the same source category. As a result, standards of performance for existing sources cannot be inconsistent with those for new sources. At the same time, the States (and EPA) are afforded a degree of flexibility in conducting a BSER analysis and establishing standards of performance for existing sources to account for the additional costs and implementation challenges associated with retrofitting these facilities to include emissions control technology. Thus, despite the consistency between the two programs, standards of performance for existing sources are expected to be—and typically are—less stringent than those for new sources.

B. EPA’s Proposed Section 111(d) Rule Is Unrelated To, Significantly Broader Than, And Inconsistent With The Proposed Section 111(b) Rule

In the proposed rule, EPA has entirely ignored the necessary nexus between Sections 111(b) and 111(d) and has developed a fully independent approach for establishing standards of performance for existing sources that is fundamentally inconsistent with the BSER analysis and standards of performance that EPA proposed for new sources earlier this year. There is no reason for EPA to abandon the BSER analyses that it conducted for coal- and natural gas-fired EGUs mere months ago and instead adopt an entirely distinct, broad-based BSER analysis that

incorporates the entire electricity sector “from plant to plug.”⁴⁴ Section 111 dictates that standards of performance for existing sources under Section 111(d) should be a more limited and flexible version of the standards of performance established by EPA for new sources under Section 111(b). If finalized, the proposed rule would do the opposite and unlawfully expand the scope of the existing source rule to new categories of sources while imposing standards of performance that are more stringent than those EPA has proposed for new sources.

First, EPA unlawfully combines coal- and natural gas-fired EGUs into a single source category for purposes of determining the best system of emission reduction adequately demonstrated. EPA flatly rejected this approach in its proposed regulation of new sources under Section 111(b). When EPA first proposed standards of performance for GHG emissions from new fossil fuel-fired EGUs on April 13, 2012, it combined coal-fired EGUs and NGCC facilities into a single source category and, after conducting a single BSER analysis, proposed a standard of performance based on emissions levels with which NGCC facilities could “readily comply,” but coal-fired EGUs could not. 77 Fed. Reg. 22,392, 22,410 (Apr.13, 2012). EPA subsequently withdrew that proposal, 79 Fed. Reg. 1,352 (Jan. 8, 2014), and proposed separate standards for coal- and natural gas-fired EGUs, 79 Fed. Reg. at 1,432. EPA based this reversal on its determination that both coal- and natural gas-fired EGUs would be viable options for new generating capacity and that different control technologies would be relevant to each. *Id.* at 1,434.⁴⁵ This approach appropriately recognized that critical differences between coal- and natural gas-fired EGUs required distinct BSER analyses and different standards of performance.

Here, in contrast, EPA has effectively ignored the differences between coal- and natural gas-fired EGUs and has conducted a single BSER analysis under Section 111(d) for all affected EGUs. This is inconsistent with EPA’s treatment of these source categories under Section 111(b). *See, e.g., Friedmand v. Sebelius*, 686 F.3d 813, 827 (D.C. Cir. 2012) (“The Secretary’s decision ... was arbitrary and capricious with respect to the length of their exclusion because it failed to explain its departure from the agency’s own precedents.”). Further, the reasons that EPA rejected a single source category in Section 111(b) are even more compelling here. While there are critical differences between new coal- and natural gas-fired EGUs that require different control technologies, entities seeking to construct new electricity generation capacity ostensibly have a choice between the two types of facilities. Indeed, this was EPA’s basis for combining the two sources categories in its original Section 111(b) proposal. That choice does not exist for existing sources because a coal-fired EGU cannot become an NGCC facility. Instead, existing sources are necessarily constrained by past design decisions that limit opportunities to install pollution controls. Thus, as EPA has recognized in the past, these constraints may require EPA to subdivide existing sources into more subcategories under 111(d), not to aggregate sources into even fewer source categories. 40 Fed. Reg. at 53,341 (“Thus, while there may be only one

⁴⁴ Press Release, EPA, Remarks for Administrator McCarthy, Announcement of Clean Power Plan, Washington, DC (June 2, 2014), *available at* <http://yosemite.epa.gov/opa/admpress.nsf/d0cf6618525a9efb85257359003fb69d/0a8e7164bb15185985257ceb0050c967!OpenDocument>.

⁴⁵ EPA’s combined standard of performance in the 2012 proposal was based in part on EPA’s mistaken belief that few, if any, new coal-fired EGUs would be constructed. *Id.*

standard of performance for new sources of designated pollutants, there may be several emission guidelines specified for designated facilities based on plant configuration, size, and other factors peculiar to existing facilities.”).

Second, in the proposed rule, EPA acts inconsistently with the Section 111(b) proposal by unlawfully ignoring the source-specific nature of the systems of emission reduction evaluated by EPA in the Section 111(b) proposal. Instead, EPA relies on a BSER analysis that is focused primarily on emission reductions that are accomplished beyond the fence line of affected EGUs by other, unrelated “zero-emission” nuclear and renewable energy sources. Indeed, many of the reductions would be accomplished by consumers of electricity rather than generators. In the Section 111(b) proposal, EPA considered three systems of emission reduction in its BSER analysis for coal-fired EGUs:

- (1) Highly efficient new generation technology that does not include any level of [carbon capture and storage (“CCS”)],
- (2) highly efficient new generation technology with “full capture” CCS (that is, CCS with capture of at least 90 percent CO₂ emissions) and
- (3) highly efficient new generation technology with “partial capture” CCS (that is, CCS with capture of a lower level of CO₂ emissions).

79 Fed. Reg. at 1,469.

Likewise, for NGCC facilities, EPA considered three alternative systems of emission reduction in its BSER analysis: “(i) The use of full or partial capture CCS; and two types of efficient generation without any CCS, including (ii) high efficiency simple cycle aeroderivative turbines; and (iii) natural gas combined cycle (NGCC) technology.” *Id.* at 1,485. Significantly, each of these systems is based on technological improvements that can be implemented on site by each new facility. In this proposal, EPA ignored Congress’ intent that “a similar approach [to that applied to new sources] (making allowances for the costs of controlling existing sources) was appropriate for the pollutants to be controlled under section 111(d),” 40 Fed. Reg. at 53,342, and conducted an entirely unrelated BSER analysis that incorporates emission reductions that may be achieved anywhere in the electricity generation, transmission, or consumption sectors. By incorporating emission reductions derived from redispatching other facilities in lieu of affected EGUs and promoting alternative generating units and demand-side energy efficiency, EPA has divorced the BSER analysis from the existing sources that are subject to regulation and from the approach it took in the Section 111(b) proposal. Consistent with Congress’ intent, EPA must use the systems of emission reduction evaluated in the BSER analysis for new sources as its starting point and then make adjustments as necessary to account for cost and other factors relevant to existing sources. Thus, for coal-fired EGUs, efficiency improvements would likely be selected as BSER for existing coal-fired EGUs because EPA has concluded that full and partial CCS technologies are too costly. 79 Fed. Reg. 1,477 (full CCS too costly for new coal-fired EGUs); 79 Fed. Reg. at 34,857 (partial CCS too costly for existing coal-fired EGUs). In sum, EPA completely ignored the systems of emission reduction that should have served as the starting point for its BSER analyses for existing sources under Section 111(d) and instead focused on emission reductions that could be accomplished beyond the fence line by facilities unrelated to the existing fossil fuel-fired EGUs that are the subject of this rule.

Third, EPA turns the flexibility that should be afforded to existing sources on its head and proposes binding emissions guidelines that are more stringent than the standards of performance it has proposed for new sources under Section 111(b). In the Section 111(b) rulemaking, EPA has proposed a standard of 1,100 lbs CO₂/MWh for new coal-fired EGUs and standards of 1,100 lbs CO₂/MWh or 1,000 lbs CO₂/MWh for NGCC facilities, depending on their size. 79 Fed. Reg. at 1,502, 1,510. Here EPA has proposed binding State-specific emissions targets for 30 States that are more stringent than the standard of performance for new coal-fired EGUs. 79 Fed. Reg. at 34,957-58.⁴⁶ In other words, despite the fact that existing facilities are more constrained in the types of emissions controls that can be employed, EPA has proposed a standard that, for most States, is lower than the standard imposed on new facilities. This is unprecedented under Section 111(d) and flatly contradicts EPA's prior conclusions that Section 111(d) emissions guidelines should be less stringent than Section 111(b) standards of performance.⁴⁷

The defects in EPA's approach are even more apparent when the emissions targets are compared to the standards of performance that EPA has proposed for reconstructed coal-fired EGUs under Section 111(b). There, EPA proposed a standard of performance of 2,100 lbs CO₂/MWh or 1,900 lbs CO₂/MWh depending on the size of the facility. 79 Fed. Reg. 34,960-34,962 (June 18, 2014). EPA considered and rejected several systems of emission reduction that would have yielded greater emission reductions after concluding that they were infeasible due to cost and design constraints at sources that had already been constructed. *See id.* at 34,891-82. It defies logic—and the intended coherence between Sections 111(b) and 111(d)—for EPA to assert that a coal-fired EGU that undergoes an extensive reconstruction project can meet a standard no more stringent than 1,900 lbs CO₂/MWh while other existing sources that make no operational changes at all can be expected to achieve emissions limitations that are twice as stringent.⁴⁸

VI. EPA LACKS THE AUTHORITY TO SET BINDING STATE EMISSION RATE TARGETS

A. The Clean Air Act Gives States, Not EPA, The Authority To Impose Standards Of Performance Under Section 111(d) And To Adjust Those Standards To Reflect Their Economic Impact

In the proposed rule, EPA unlawfully usurps the States' authority under Section 111(d) to establish standards of performance for GHG emissions from existing fossil fuel-fired EGUs. The

⁴⁶ For 26 States, the emissions targets are also lower than the proposed standard of performance for large NGCC facilities.

⁴⁷ It is also contrary to EPA's regulations, which permit States to use the flexibility granted by Section 111(d) to set less stringent performance standards than the emission guidelines determined by the Agency. 40 C.F.R. § 60.24(f). *See* Section VI.A.3., *infra*.

⁴⁸ 25 of 49 States have emission reduction targets of less than 950 lbs CO₂/MWh. 79 Fed. Reg. at 34,957-58.

plain meaning of Section 111, as well as the principles of cooperative federalism on which the CAA is based, dictate that States be given the same authority to establish standards of performance under Section 111(d) as EPA exercises under Section 111(b). Here, EPA has effectively removed such authority from the States by conducting a BSER analysis and proposing binding emission reduction targets from which the States have virtually no discretion to deviate. As a result, if the proposal were finalized, EPA would be effectively establishing the standard of performance for each State, leaving the States with no role other than to implement the standard that EPA has already established. Such a regulation would be inconsistent with and unlawful under the Clean Air Act.

1. States Must Have the Opportunity to Exercise the Same Authority Under Section 111(d) That EPA Exercises Under Section 111(b)

Traditional canons of statutory construction dictate that States exercise the same authority with respect to existing sources under Section 111(d) as EPA exercises with respect to new sources under Section 111(b). Section 111(b) directs EPA to “establish[] Federal standards of performance for new sources within such category,” while Section 111(d) directs *States* to “establish standards of performance for any existing source ... to which a standard of performance would apply if such existing source were a new source.” When identical words—such as the direction to “establish standards of performance”—are used in different subparts of the same statutory provision, they must be given the same meaning. *See Gustafson*, 513 U.S. at 570; *ACF Indus., Inc.*, 510 U.S. at 342; *Retzlaf*, 510 U.S. at 143. Thus, when establishing standards of performance for existing sources under Section 111(d), States must be permitted to exercise the same authority that EPA exercises under Section 111(b): namely to conduct a BSER analysis, select the best system of emission reduction for a source category or subcategory, and then translate that into a source-specific emission standard.

EPA, by contrast, has a much more limited role under Section 111(d). In the first instance, EPA is merely directed to “prescribe regulations *which shall establish a procedure ...* under which each State shall submit to the Administrator a plan which establishes standards of performance for existing sources.” 42 U.S.C. § 7411(d)(1) (emphasis added). The division of authority is clear. EPA establishes procedures while the States establish standards of performance. Only in the event that a State “fails to submit a satisfactory plan” is EPA given permission to establish standards of performance for existing sources. *Id.* § 7411(d)(2). This division of labor is entirely consistent with the principles of cooperative federalism on which the Clean Air Act is based. *Sierra Club v. Korleski*, 681 F.3d 342, 343 (6th Cir. 2012) (Clean Air Act intended to be “a model of *cooperative* federalism”). EPA takes the initial lead in developing standards of performance for new sources that can be applied on a nation-wide level. Then States, who have a closer working relationship with and understanding of existing sources within their borders, take the lead under Section 111(d) to establish standards of performance for existing sources that are informed by EPA’s prior BSER analysis for new sources under Section 111(b). While deferring to the States’ reasoned judgment with respect to standards of performance, EPA nonetheless retains an oversight role in ensuring that the standards of performance included in State implementation plans are satisfactory and in serving as a backstop if satisfactory State implementation plans are not developed.

2. EPA's Regulations Are Unlawful Because They Usurp the States' Authority to Establish Standards of Performance for Existing Sources

In contrast to its limited authority to establish procedures to facilitate State regulatory action, EPA effectively usurps the entire process of setting standards of performance in the first instance. EPA has already completed—without any input from the States—the central action in establishing standards of performance: conducting the BSER analysis and selecting the “best system of emission reduction ... adequately demonstrated.” *See* 79 Fed. Reg. at 34,878-92. EPA then went further and has proposed *binding* emission reduction targets that each State would be legally obligated to meet. *See* 79 Fed. Reg. at 34,892 (“the interim and final goals will be binding emission guidelines for state plans”); *see also* proposed 40 C.F.R. § 60, Subpart UUUU; *id.* § 60.5740(a)(3)(ii) (performance level in State plan “must be equivalent to or better than the levels of the rate-based CO₂ emission performance goals in Table 1 of this Subpart ...”). This is clearly unlawful. Even assuming, *arguendo*, that EPA has authority under Section 111(a)(1) to determine the “best system of emission reduction ... adequately demonstrated,” States must determine “the degree of emissions limitation achievable through the application” of that system. In other words, even if EPA has authority to determine the emission controls that qualify as BSER, it is the States that must apply those emission controls to existing sources and determine the numeric standard of performance that such sources can attain. Thus, by both selecting the best system of emission reduction adequately demonstrated and then choosing a numeric standard that reflects the application of that system, EPA has effectively established the standard of performance for existing fossil fuel-fired EGUs under Section 111(d). Even if a State were to determine that the emission reduction targets set by EPA were inappropriate and could not reasonably be achieved, it would still be required to submit an implementation plan that satisfies EPA’s binding targets, or risk the imposition of a federal implementation plan administered by EPA. All that is left for States to do under EPA’s proposal is to determine whether it will subject some sources to even greater emission reduction obligations so that it might decrease obligations on other sources. And even then, the States’ discretion to shift compliance obligations in their implementation plans will be significantly curtailed because EPA’s aggressive emission reductions targets leave little flexibility under any of the Building Blocks for States to impose additional obligations beyond those included in EPA’s targets. This is plainly contrary to Congress’ intent and the plain meaning of Section 111(d) which directs the “States”—not EPA—to “establish” standards of performance and, therefore, is unlawful.

Although EPA had previously recognized that States should be entitled to at least provide for less stringent emission standards than those reflected in EPA’s “guideline documents,” EPA would not permit even this flexibility in connection with the proposed rule. Here, EPA has proposed to prohibit States from exercising even this limited discretion in their implementation plans. 79 Fed. Reg. at 34,925-26. Instead, rather than adhering to the statute and to EPA’s own implementing regulations, EPA would prohibit States from adjusting the standards of performance to account for specific challenges posed by individual plants and would instead require States to make up for any deviations from EPA’s standards of performance by imposing even more draconian emission reductions on other facilities. *Id.* at 34,926 (“If a state prefers not to attempt to achieve a level of performance estimated by the EPA for a particular building block, it can compensate through over-achievement in another one, or employ other compliance approaches not factored into the state-specific goals at all.”). In sum, EPA’s proposal completely

usurps the States’ statutory right to establish standards of performance for existing sources under Section 111(d)—even though the statute mandates that States “establish” those standards.

3. EPA Fails to Give States Appropriate Flexibility to Adjust Emission Reduction Targets as Required by Section 111(d)

Relatedly, the proposed rule is unlawful because it would preclude States from exercising the flexibility specifically provided for by Congress in Section 111(d) in “applying a standard of performance.” 42 U.S.C. § 7411. One of the central features of Section 111(d) is the flexibility it affords States to provide reasonable standards of performance for specific facilities or groups of facilities based on their own unique attributes. While it may be practicable under some circumstances to establish uniform standards on new sources based on the fact that the control technology needed to achieve those standards can be incorporated into the facilities at the initial design phase, the same cannot be said for existing sources. Existing sources that were not constructed with new pollution control technologies in mind are typically far less homogenous and are constrained by past decisions regarding site layout. As a result, certain pollution control technologies may not be technically feasible, and others may prove less effective than they would under optimal design conditions. Finally, in some cases, the cost of certain emission control technologies may be unreasonable due to the source’s limited remaining useful life.

Congress, in enacting Section 111(d), recognized these challenges and gave States additional flexibility to establish standards of performance for existing sources. Specifically, Congress authorized States “to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies.” 42 U.S.C. § 7411(d)(1)(B). While Congress did not specify the “other factors” that States could consider, EPA has previously determined that these factors include, but are not limited to, costs associated with plant age, location, or basic process design or the physical inability of installing certain control technology. 40 C.F.R. § 60.24(f). Further, as EPA has recognized, States can evaluate the viability of control technologies on a case-by-case basis for individual facilities or classes of facilities. *Id.* This inherent flexibility in the Section 111(d) program allows States to strike an appropriate balance between emission reductions and the economic interests of regulated facilities, their investors, and their customers by adjusting—as appropriate—generally applicable standards of performance to account for source-specific circumstances.

a) EPA’s Proposed Rule Unlawfully Prohibits States from Adjusting Standards of Performance to Account for Remaining Useful Life and Other Source-Specific Factors

In the proposed rule, EPA unlawfully prohibits States from applying the flexibility inherent in Section 111(d)—and in EPA’s own regulations—to deviate from EPA’s emissions guidelines on a case-by-case basis. First, EPA effectively forecloses any possibility of altering a State’s proposed emission reduction target to account for remaining useful life or any other relevant factors, even if a State can establish that EPA erred in its assessment of the States’ ability to achieve one or more of the Building Blocks. 79 Fed. Reg. at 34,893 (“Accordingly, EPA proposes that even if a State demonstrates during the comment period that application of a building block to that State would not result in the level of emission reductions reflected in the EPA’s quantification for that State, then the State should also explain why the application of the

other building blocks would not result in greater emission reductions than are reflected in the EPA's quantification for that state."'). Thus, EPA asserts that, because its guidelines apply at the aggregate State-wide level rather than to individual existing sources, States must account for emission reduction shortfalls from any Building Block by imposing even more stringent emission reduction obligations on other sources. *Id.* at 34,925 ("If a state prefers not to attempt to achieve the level of performance estimated by the EPA for a particular building block, it can compensate through over-achievement in another one, or employ other compliance approaches not factored into the state-specific goals at all.'). EPA cannot declare *ex ante* that it will reject as unsatisfactory the plan of any State that seeks to exercise its statutory authority to account for remaining useful life and other factors that may require a deviation from EPA's emissions guidelines.

Second, EPA goes on to suggest that "in this case, the flexibility provided in the State plan development process adequately allows for consideration of the remaining useful life of the affected facilities and other source-specific factors and, therefore, that separate application of the remaining useful life provisions by States in the course of developing and implementing their CAA section 111(d) plans is unnecessary." *Id.* at 34,925. EPA cannot usurp the States' statutory authority to evaluate, on a case-by-case basis, source-specific factors including a facility's remaining useful life and, when necessary, deviate from EPA's emissions guidelines. The flexibility to consider remaining useful life, in particular, was unequivocally reserved to the States by Congress when it enacted Section 111(d), and this flexibility is reinforced by EPA's own implementing regulations. EPA fails to identify any statutory provision or canon of statutory construction that would allow it to eliminate the statutory flexibility that Congress intended for the States to exercise. Indeed, rewriting Section 111(d) in such a fashion is flatly inconsistent with the principles of cooperative federalism on which the CAA is based.

EPA's sole justification for its proposal is the fact that it has provided sufficient flexibility in the State emission reduction targets to allow States to account for remaining useful life and any other source-specific challenges by shifting the responsibility for emission reductions to other sources in the State. When, for source-specific reasons, an existing facility cannot meet the emissions limit associated with a more broadly applicable system of emission reduction, Section 111(d) contemplates that States provide relief to that source by applying a less stringent emissions limitation. EPA's approach requires an additional unlawful step whereby a State must also identify and impose additional obligations on another source that is capable of achieving additional emission reductions beyond those required by the best system of emission reduction. This is inconsistent with Congress' intent. The consideration of remaining useful life and other relevant factors is a one-way ratchet that provides relief to sources that cannot achieve the emission reductions embodied by a generally applicable best system of emission reduction. EPA turns that approach on its head and prohibits a State from providing such relief to a specific facility unless it can identify another facility to "punish" by requiring additional emission reductions to offset that relief.

EPA's proposal is also arbitrary and capricious. As explained in Section VII.E., *infra*, EPA's building block analyses suffer from a number of serious deficiencies. Even if the emission reduction targets in individual building blocks can be achieved in the abstract, there is no guarantee that they can be met in the aggregate, particularly with any significant margin for error. Thus, the flexibility that EPA asserts is "inherent" in State emission performance goals, 79

Fed. Reg. at 34,925, is largely illusory because EPA’s BSER analysis goes beyond what is “reasonable” and approaches—if not exceeds—the “maximum amount [of emission reduction] that could be achieved” by each building block. *Id.* at 34,893. Thus, contrary to EPA’s assertions, States that cannot achieve the emission reductions required under one Building Block may not be able to find sufficient flexibility under other Building Blocks to offset those shortfalls.

b) The Inability to Adjust Standards of Performance to Account for Remaining Useful Life Will Impose Hardships on the States and on Existing Coal-Fired EGUs

EPA’s proposal to prohibit States from relying on remaining useful life and other factors on a case-by-case basis to adjust standards of performance for existing sources will have significant detrimental effects on affected EGUs and on the States’ ability to achieve EPA’s proposed emission reduction targets. First, EPA fails to appropriately account for, at a minimum, the more than 70,000 MW of facilities that have already been retired since the 2012 baseline or may be scheduled to retire during the interim compliance period or shortly thereafter. Even in the absence of the proposed rule, a number of coal-fired EGUs would be retired for economic reasons after reaching the end of their useful life. For facilities that would otherwise retire during the interim compliance period or shortly after the final standards of performance take effect, it may not be economical to impose significant heat rate improvements. Under the flexible approach intended by Congress, States could limit—or forego entirely—emission reductions for such facilities on grounds that they will soon be retired and will then cease to emit entirely. Under EPA’s proposed approach, however, States could not require anything less than six percent heat rate improvements on such facilities without imposing additional emission reduction obligations on other affected entities. Further, because EPA assumes that all emission reductions associated with Blocks 1 and 2 can be implemented by 2020, States must either identify other emission reductions—for example by accelerating implementation of RPS or EERS programs—or require costly over-compliance later in the interim period which will ultimately prove unnecessary to achieve the final emission reduction targets. Not only will such an approach strip the States of their right to account for the remaining useful life of existing sources, it will dramatically increase compliance costs by accelerating the compliance schedules for other Building Blocks ahead of those analyzed by EPA.

Second, as EPA acknowledges, the aggressive emission reduction targets set by EPA would dramatically reduce the amount of coal generation nationwide and would result in the retirement of a significant number of coal-fired EGUs. Under EPA’s building block approach, coal generation will be reduced by 26%, from 1.47 billion MWh to 1.10 billion MWh.⁴⁹ Such a large reduction in coal generation will necessarily result in a large number of plant closures, as coal-fired EGUs will not be able to operate economically at lower capacities. EPA’s own data corroborate the fact that the rule would cause the closure of coal-fired EGUs. EPA projects that implementation of all four Building Blocks will directly result in the retirement of an additional

⁴⁹ EPA, Data File: Goal Computation –Appendix 1 and 2, *available at* <http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-technical-documents>.

46-49 GW of coal-fired EGU capacity beyond what is already projected as a result of MATS and other existing EPA regulations. 79 Fed. Reg. at 34,933. Indeed, EPA's BSER analysis projects that coal-fired generation will cease entirely in 11 States.⁵⁰ It is patently unreasonable to suggest that all the coal-fired EGUs that EPA projects will retire by 2030 will have reached the end of their useful lives and would have been retired even in the absence of this rulemaking. If States were permitted to consider the remaining useful life of existing sources when setting standards of performance, they may impose less stringent standards that would avoid the premature closure of coal-fired EGUs. However, the aggressive emission reduction targets proposed by EPA effectively foreclose that option, as the targets cannot be met without a dramatic reduction in coal-fired electricity generation.

The premature retirement of coal-fired EGUs, in particular, will cause significant hardship. Constructing a coal-fired EGU is costly, and the owners of such facilities depend on long-term revenues throughout the entire useful life of the facility to justify those significant up-front capital costs. For many existing coal-fired EGUs, those capital costs have increased over time as facilities have become subject to increasingly stringent federal environmental regulations. Indeed, most recently, EPA's MATS rulemaking subjected coal-fired EGUs to significant new compliance costs. While a number of facilities have been forced to close, EPA projected that the remaining sources would spend nearly \$10 billion to comply with the MATS NESHAP.⁵¹ Thus, between the initial capital costs and more recent compliance costs associated with environmental regulations, many coal-fired EGUs that would be forced to retire under EPA's proposal would be unable to recoup their capital investments. This raises a serious equitable concern as these facilities—which provide a necessary service to their communities—operate under State and federal permits and have a reasonable expectation that those who regulate them will allow them to operate long enough to recover the costs of their initial investment and, more importantly, the additional environmental compliance costs that those regulators have imposed on them. Moreover, there will remain a serious question of who should be responsible for bearing the economic burden of the stranded assets that will result from the premature closure of these coal-fired EGUs.

Further, issuing regulations that would necessitate the closure of coal-fired EGUs and produce significant stranded assets raises significant questions under the Takings Clause of the Fifth Amendment. Under the familiar *Penn Central* test, a court evaluates a regulatory takings claim by considering the regulation's economic effect on the landowner, the extent to which the regulation interferes with reasonable investment-backed expectations, and the character of the government action." *Palazzolo v. Rhode Island*, 533 U.S. 606, 617 (2001) (citing *Penn Central*

⁵⁰ EPA projects that coal-fired generation will stop in Alaska, Arizona, California, Connecticut, Massachusetts, Mississippi, Nevada, New Hampshire, New Jersey, Oregon, and Washington. EPA, Data File: Goal Computation –Appendix 1 and 2, *available at* <http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-technical-documents>.

⁵¹ See EPA Fact Sheet: Mercury and Air Toxics Standards: Benefits and Costs of Cleaning Up Toxic Air Pollution from Power Plants, *available at* <http://www.epa.gov/mats/pdfs/20111221MATSimactsfs.pdf>.

Transp. Co. v. New York City, 438 U.S. 104, 124 (1978)). First, the economic effect on the owner would be substantial: the owner would likely be deprived of all economic benefits if it were forced to shut down a coal-fired EGU prematurely.⁵² Further, such a premature retirement would interfere with the reasonable investment-backed expectations of the facility owner. When a coal-fired EGU is approved for construction, the owner has a reasonable investment-backed expectation that it can operate the facility for its entire useful life to recoup the substantial costs of construction. Leaving an owner with stranded assets it cannot recover would interfere with those expectations. Expenditures necessary to comply with federal environmental regulations create further investment-backed expectations. By mandating the closure of coal-fired EGUs immediately after they installed controls to comply with MATS, EPA's proposal would prevent the facilities from recouping any of their compliance costs in addition to any remaining construction costs. While EPA may be able to point to environmental benefits associated with prematurely shutting down coal-fired EGUs, it is doubtful that such benefits could offset the other factors in the *Penn Central* test. At a minimum, Section 111(d) must be read to authorize States to adjust their emission reduction targets to take into account the remaining useful life of affected EGUs.

Given the significance of these potential impacts, EPA correctly acknowledged in its October 30th NODA that adjustments in compliance may be necessary to account for the remaining useful life of coal-fired EGUs, but the NODA does not sufficiently address this issue. *See* 79 Fed. Reg. 64,543. Specifically, EPA "requests comment on whether, and how, book life might be either used as part of the basis for the development of an alternative emission glide path for building block 2 or used to evaluate whether other ways of developing an alternative glide path ... would address stakeholders' stranded investment concerns." *Id.* at 65,549. However, a proper evaluation of remaining useful life requires a source-by-source analysis, and the brief comment period EPA has allocated for the NODA prevents the Associations from providing any substantive comments on how remaining useful life could be incorporated into a final Section 111(d) rule. Further, given the diversity among existing coal-fired EGUs, it would be inappropriate for EPA to adopt a uniform 40-year book life for all existing coal-fired EGUs. *See id.* Instead, each existing coal-fired EGU must be evaluated on a case-by-case basis to determine its remaining useful life.

4. EPA's Previously Implemented Rules Cannot Enable It to Depart from Section 111(d) and Justify the Approach Adopted in the Proposed Rule

Finally, EPA cannot avoid scrutiny of its regulatory approach by claiming that it is acting in compliance with its own existing Section 111(d) regulations (40 C.F.R. § 60, subpart B) when those regulations are inconsistent with Clean Air Act. First EPA's Section 111(d) regulations are unlawful because they contradict the plain meaning of the Clean Air Act and usurp the States'

⁵² In fact, to the extent that a mandated plant closure resulting in stranded assets would deny a facility owner "all economically beneficial or productive use" of the facility, it could raise questions of a *per se* regulatory taking. *See Lucas v. South Carolina Coastal Council*, 505 U.S. 1003, 1015 (1992).

authority to conduct BSER analyses and establish standards of performance for existing sources. Second, EPA's proposed rule is inconsistent with those regulations.

As EPA explains in the proposed rule, in 1975, the Agency previously adopted implementing regulations for Section 111(d) which EPA now cites as authority to impose binding emissions "guidelines" that must be achieved through State Section 111(d) implementation plans. EPA explained its preferred regulatory approach in the preamble to the 1974 proposal for those implementing regulations:

Accordingly, EPA will publish guideline documents (discussed below) describing available systems of emission control that have been demonstrated, select a system which is judged to be the best when costs are taken into account, and specify an emission limitation in § 60.29 that reflects the application of such a system. State plans that include an emission standard equal to or more stringent than the specified limitation will be approvable.

39 Fed. Reg. at 36,102. Pursuant to the 1975 implementing regulations, EPA now claims that it is fully authorized to conduct a BSER analysis and establish emissions "guidelines" that are legally binding on the States. Prior to this rulemaking, the Associations have had no basis for challenging EPA's regulations because their members were not regulated by EPA and the States pursuant to Section 111(d). Here, for the first time, EPA has proposed to apply those regulations to the Associations' members' existing fossil fuel-fired EGUs in a manner that, if finalized, would cause their members harm. *See* Section II., *supra*. Therefore, the Associations' grounds to seek judicial review of EPA's interpretation in the 1975 implementing regulations would ripen upon finalization of this rulemaking and EPA's promulgation of this rule would be grounds arising after for challenging those regulations. *See Coalition for Responsible Regulation*, 684 F.3d 102, 130 (D.C. Cir. 2012).

Foremost, EPA cannot simply rely on the 1975 implementing regulations under Section 111(d) because they are unlawful. When it issued the implementing regulations, EPA justified giving itself broad authority to conduct a BSER analysis and establish binding emissions limitations under Section 111(d) on the grounds that it must have a substantive standard against which to judge the sufficiency of State implementation plans. *See* 40 Fed. Reg. at 53,343 ("[I]t would make no sense to interpret Section 111(d) as requiring the Administrator to base approval or disapproval of state plans solely on procedural criteria."). But EPA's interpretation of the 1975 regulations negates Congress' express language providing that *States* should "establish[] standards of performance for any existing source for any air pollutant." 42 U.S.C. §7411(d). Further, as explained in greater detail below, any ambiguity in Section 111(d) must be resolved in favor of an interpretation that protects States' rights and the States' preeminent role in regulating electricity markets. *See* Section VII.C., *infra*.

The provision of Section 111(d) that authorizes EPA review of State plans can be easily harmonized with the States' preeminent role in setting standards of performance. In fact, EPA's proposed rule provides a series of substantive criteria that can be used to judge whether standards of performance and the systems of emission reduction set by States are satisfactory without dictating them in the first instance:

- The system of emission reduction must be technically feasible.
- The EPA must consider the amount of emission reductions that the system would generate.
- The costs of the system must be reasonable. The EPA may consider costs at the source level, the industry level, and, at least in the case of the power sector, the national level in terms of the overall costs of electricity and the impact on the national economy over time.
- The EPA must also consider that CAA Section 111 is designed to promote the development and implementation of technology, including the diffusion of existing technology as the BSER, the development of new technology that may be treated as the BSER, and the development of other emerging technology.

79 Fed. Reg. 34,879 (internal citations omitted).

EPA acknowledges that courts have successfully conducted substantive reviews of EPA’s standards of performance for new sources under Section 111(b) by applying these criteria, and there is no reason to suggest that EPA could not apply similar criteria to determine whether the standards of performance established by the States under Section 111(d) are satisfactory. For example, under this approach, EPA could still evaluate whether a State failed to include in its evaluation a particular system of emission reduction that might be applicable to a given source category. EPA could also consider whether States appropriately weighed the costs of particular systems of emission reduction when selecting a standard for each existing facility. However, like a court’s review of standards of performance established by EPA under Section 111(b), EPA’s review of standards of performance established by the States under Section 111(d) would have to be deferential. *See Nat’l Asphalt Pavement Ass’n*, 539 F.2d at 786 (“The standard of review of actions of the Administrator in setting standards of performance is an appropriately deferential one”). In sum, EPA cannot save this unlawful proposal and ignore the plain text of Section 111(d) by asserting that establishing binding emissions guidelines are the only way to provide a substantive basis to evaluate State implementation plans.

EPA also ignores the fact that its 1975 implementing regulations grant States a significant degree of flexibility that the proposed rule would not allow. *See* 40 C.F.R. § 60.24(f). EPA’s assertion that it “has discretion [under the 1975 implementing regulations] to alter the extent to which States may authorize relaxations to standards of performance that would otherwise apply to a particular source or source category,” 79 Fed. Reg. at 34,925, misses the point. As explained above, the States’ ability to deviate from these standards of performance is a statutory creation—not a regulatory one—and EPA cannot rely on the regulations it has previously adopted to take away what Congress has given. Further, EPA’s 1975 implementing regulations state that EPA may preclude a State from adopting “less stringent emissions standards” only where EPA makes a specific “case-by-case” assessment for “particular designated facilities” that such variance is unwarranted. In the proposed rule, however, EPA has made no assessment that it would be inappropriate to allow less stringent standards for particular facilities to account for costs, design and other relevant factors. EPA is therefore acting inconsistently with its existing regulations for implementing Section 111(d).

B. The Proposed Rule Is Contrary To The Division Of Authority Established By Congress Under The Federal Power Act

The proposed rule also intrudes on the States' traditional and exclusive authority to regulate local and intrastate electricity resources, and should be withdrawn for this reason. The Federal Power Act ("FPA") creates a division of responsibility between the States, on one hand, and the federal government (through FERC), on the other, reserving to the States jurisdiction "over facilities used for the generation of electric energy or over facilities used in local distribution or only for the transmission of electric energy in intrastate commerce." 16 U.S.C. § 824(b)(1). In turn, "[f]ederal regulation ... extend[s] only to those matters which are *not* subject to regulation by the States." *Id.* § 824(a) (emphasis added); *see Ark. Elec. Co-op. Corp. v. Ark. Pub. Serv. Comm'n*, 461 U.S. 375, 377-78 (1983); *Fed. Power Comm'n v. S. Cal. Edison Co.*, 376 U.S. 205, 215-16 (1964).

Numerous judicial decisions have read the FPA and the other federal energy statutes as retaining the States' "traditional responsibility in the field of regulating electrical utilities for determining questions of need, reliability, cost and other related state concerns." *Pac. Gas & Elec. Co. v. State Energy Res. Conservation & Dev. Comm'n*, 461 U.S. 190, 205 (1983); *see also New York v. FERC*, 535 U.S. 1, 20 (2002) ("FERC's jurisdiction over the sale of power has been specifically confined to the wholesale market." (emphasis omitted)); *Niagara Mohawk Power Corp. v. FERC*, 452 F.3d 822, 824 (D.C. Cir. 2006) ("States retain jurisdiction over retail sales of electricity and over local distribution facilities."); *Duke Energy Trading & Mktg., L.L.C. v. Davis*, 267 F.3d 1042, 1056 (9th Cir. 2001) ("Retail sales of electricity ... are within the exclusive jurisdiction of the States"). As a result, the courts have consistently rejected federal attempts to intrude on the States' authority in these areas. *See, e.g., S. Cal. Edison Co. v. FERC*, 603 F.3d 996, 1000-02 (D.C. Cir. 2010) (FERC lacked jurisdiction to preempt State authority to "set the netting period for station power—i.e., the pricing mechanism—in the retail market"); *Piedmont Envtl. Council v. FERC*, 558 F.3d 304, 315 (4th Cir. 2009) (FERC lacked permitting authority where a State commission "engage[d] in a legitimate use of its traditional powers"); *Detroit Edison Co. v. FERC*, 334 F.3d 48, 54 (D.C. Cir. 2003) (ruling that FERC actions infringed on State retail jurisdiction).

Here, EPA's proposed rule contravenes the "bright line ... between state and federal jurisdiction" under the FPA. *Nantahala Power & Light Co. v. Thornburg*, 476 U.S. 953, 966 (1986); *see Ark. Elec. Co-op.*, 461 U.S. at 377-78. For example, EPA's Building Block 2 calls for replacing coal- and oil/gas-fired generation with NGCC generation, but that is precisely the type of dispatching decision that is left to the States under the FPA. *See Detroit Edison Co.*, 334 F.3d at 49 ("Retail service [subject to State authority] ... denotes transmission or distribution to end users."); *see also In re S. Cal. Edison Co.*, D. 05-01-054, 2005 WL 350964 (Cal. P.U.C. Jan. 27, 2005) (discussing State regulation of dispatch). To meet the emission reduction targets, State regulators would have no choice but to mandate increased dispatch of NGCC at the expense of coal/oil-fired EGUs, regardless of the efficiency and costs of doing so—and ultimate impact on retail rates. The unlawfulness of EPA's approach applies equally to EPA's proposal to prioritize the dispatch of existing NGCC facilities, 79 Fed. Reg. at 34,862-66, and EPA's suggestion in the NODA that its BSER analysis could be expanded to include new NGCC facilities, 79 Fed. Reg.

at 64,549-51.⁵³ Likewise, requiring the construction of new renewable power plants to serve retail demand is clearly not within the federal government’s limited authority over “wholesale” transmission. And in Building Block 4, by seeking to regulate local and intrastate electricity markets in the name of reducing demand, EPA is usurping the States’ traditional authority over those markets. The FPA clearly recognizes States’ authority with respect to the generation and dispatch of electricity, and nothing in the Clean Air Act suggests that Congress has independently given EPA authority to compel fuel switching within the electricity sector.

Further, to the extent that there is a federal role to play in regulating dispatch or demand-side energy efficiency, that role has been assigned to FERC and not to EPA. *See* 16 U.S.C. § 824(a). As explained in Section IX.D., *infra*, EPA’s role with respect to energy efficiency is limited to promoting voluntary programs. Indeed, regardless of EPA’s general authority under Section 111(d), Congress, in the FPA, made FERC the sole federal agency with authority over the generation, dispatch, and consumption of electricity. *See Morton*, 417 U.S. at 550-51 (“Where there is no clear intention otherwise, a specific statute will not be controlled or nullified by a general one, regardless of the priority of enactment.”); *see also Hunter v. FERC*, 711 F.3d 155 (D.C. Cir. 2013) (holding that a federal agency has no authority to exercise jurisdiction over subject matter reserved exclusively to another agency). Thus, at a minimum, given the demarcation of authority adopted in the FPA and Congress’ decision to limit the role of the federal government in regulating electricity markets, Section 111(d) cannot be read as giving EPA authority to mandate a fundamental restructuring of those markets, as the proposed rule seeks to do.

The local-interstate division of responsibility between the States and FERC makes perfect sense. No central federal regulator can effectively regulate local generation and distribution throughout the United States. Electricity service is not perfectly fungible or uniform. There are important local limitations and constraints on distribution and generation that must be accounted for in determining dispatch. For example, some plants must be run to maintain load. Transmission bottlenecks can prevent perfectly efficient distribution, and it cannot be assumed that electricity generated from alternative sources can be transmitted to all consumers. Indeed, in States such as Texas where electricity transmission is managed by multiple ISOs, it may be virtually impossible to move electricity across ISOs from one part of the State to another. The availability of wind and solar generation will depend on local conditions that vary from State to State (and within States) and over time. The fact that the States are best situated to make these types of local policy and technical determinations is reinforced by the numerous errors EPA made in connection with the four Building Blocks in the proposed rule. *See* Section VII.E., *infra*. Thus, even if the FPA did not grant the States primacy over local electricity markets, EPA’s proposal would be ill-advised. But because the States do retain that authority, the proposed rule is unlawful.

C. The Proposed Rule Would Violate The Tenth Amendment By Commandeering State Legislative And Regulatory Functions

⁵³ As explained in Section X., *infra*, the inclusion of new NGCC facilities in a Section 111(d) rulemaking is also inconsistent with the structure of Section 111, which directs EPA to regulate newly constructed sources under Section 111(b).

“Air quality regulation under the CAA is an exercise in cooperative federalism[.]” *Dominion Transmission, Inc. v. Summers*, 723 F.3d 238, 240 (D.C. Cir. 2013); accord *Sierra Club*, 681 F.3d at 343; *Luminant Generation Co., LLC v. EPA*, 675 F.3d 917, 921 (5th Cir. 2012). The proposed rule departs from that principle and instead attempts to coerce the States into implementing a federal regulatory program in violation of the Tenth Amendment.

The “fundamental purpose” of the Constitution’s federal structure is to “secure[] to citizens the liberties that derive from the diffusion of sovereign power.” *New York*, 505 U.S. at 181 (internal quotation mark omitted); accord *Bond*, 131 S. Ct. at 2364. The Tenth Amendment codifies that concept by reserving to the States and the people all “powers not delegated to the United States by the Constitution.” U.S. CONST. amend. X. Accordingly, “if a power is an attribute of state sovereignty reserved by the Tenth Amendment, it is necessarily a power the Constitution has not conferred on Congress.” *New York*, 505 U.S. at 156. And “having the power to make decisions and to set policy is what gives the State its sovereign nature.” *FERC v. Mississippi*, 456 U.S. 742, 761 (1982).

Applying these principles, the courts have repeatedly rejected federal attempts to “compel the States to enact or administer a federal regulatory program.” *New York*, 505 U.S. at 188. In *New York*, the Supreme Court struck down a provision that “offer[ed] state governments a ‘choice’ of either accepting ownership of [radioactive] waste or regulating [it] according to the instructions of Congress.” 505 U.S. at 175. Because either option, standing alone, would impermissibly “‘commandeer’ state governments into the service of federal regulatory purposes,” Congress could not offer the States the “choice” to do one or the other. *Id.* at 176. Similarly, in *Printz v. United States*, 521 U.S. 898 (1997), the Court invalidated a statute that commanded State and local law enforcement officers to conduct background checks on handgun buyers. *See id.* at 902-04. Because the law attempted “to direct state law enforcement officers to participate ... in the administration of a federally enacted regulatory scheme,” *id.* at 904, it ran afoul of the anti-commandeering doctrine applied in *New York*: “The Federal Government may neither issue directives requiring the States to address particular problems, nor command the States’ officers ... to administer or enforce a federal regulatory program.” *Id.* at 935.

The Tenth Amendment applies with particular force in the context of the Clean Air Act, which is intended to be “a model of *cooperative* federalism.” *Korleski*, 681 F.3d at 343 (emphasis added); accord *Dominion Transmission*, 723 F.3d at 240. Thus, the Courts have not hesitated to strike down attempts by EPA to dictate to the States actions that they must take to reduce pollution. In *Brown v. EPA*, 521 F.2d 827 (9th Cir. 1975),⁵⁴ the Ninth Circuit rejected EPA’s claim that the CAA empowered it to compel California’s compliance with an EPA transportation control plan, which “directed ... California to undertake those tasks assigned to it” by the agency, including institution of a vehicle inspection program, limiting the use of

⁵⁴ *Brown v. EPA*, *Maryland v. EPA*, and *District of Columbia v. Train* were all vacated as moot by the Supreme Court when EPA “declined even to defend [the challenged regulations], and instead rescinded some and conceded the invalidity of those that remained.” *Printz*, 521 U.S. at 925; *see EPA v. Brown*, 431 U.S. 99, 103 (1977). These decisions were subsequently cited with approval in both *Printz*, 521 U.S. at 928, and *Hodel v. Virginia Surface Mining & Reclamation Ass’n, Inc.*, 452 U.S. 264, 288-89 (1981).

motorcycles, and creating bus and carpool lanes. *Id.* at 830. To avoid “serious constitutional issues,” the court refused to construe the statute to grant EPA such power, which “would reduce the states to puppets of a ventriloquist Congress.” *Id.* at 837, 839. The Fourth Circuit likewise rejected EPA’s attempt to require Maryland to enact similar regulatory programs pursuant to a transportation control plan. *Maryland v. EPA*, 530 F.2d 215 (4th Cir. 1975). The *Maryland* court explained that “if there is any attribute of sovereignty left to the states it is the right of their legislatures to pass, or not to pass, laws.” *Id.* at 225. Thus, the court did not believe that “an Act of Congress may be construed to permit an agency of the United States to direct a state legislature to legislate.” *Id.* And in *District of Columbia v. Train*, 521 F.2d 971 (D.C. Cir. 1975), the D.C. Circuit held EPA’s regulations “invalid to the extent they require[d] unconsenting states to administer and enforce the EPA-promulgated transportation control programs,” because the Constitution contemplates “direct federal regulation of the offending activity and not coerced state policing of the details of an intricate federal plan.” *Id.* at 993.

The holdings of these cases reflect not only the structure of dual sovereignty that is built into the Constitution, but also the fact that political accountability would suffer if the federal government could strong-arm the States into acting on its behalf:

[W]here the Federal Government directs the States to regulate, it may be state officials who will bear the brunt of public disapproval, while the federal officials who devised the regulatory program may remain insulated from the electoral ramifications of their decision. Accountability is thus diminished when, due to federal coercion, elected state officials cannot regulate in accordance with the views of the local electorate in matters not pre-empted by federal regulation.

New York, 505 U.S. at 169; *see also Printz*, 521 U.S. at 920-21 (“The Constitution thus contemplates that a State’s government will represent and remain accountable to its own citizens.”).

If finalized, the proposed rule would violate the Tenth Amendment because it would compel State regulatory (and likely legislative) activities—measures that lie at the heart of the States’ sovereign authority. EPA’s emission reduction requirements are based on assumptions that the States will completely restructure their electricity markets. *See, e.g.*, Section II.A.1., *supra*. To meet EPA’s emission reduction targets, States would have to, among other things, cease using efficient, least-cost dispatch and adopt new dispatch regimes that prioritize EPA’s preferred sources of generation, *see* 79 Fed. Reg. at 34,862-66; require utilities to construct renewable energy facilities, regardless of cost, *see id.* at 34,866-70; maintain all existing nuclear energy capacity, regardless of economic viability or safety concerns should a plant reach the end of its useful life, *see id.* at 34,870-71; and require reductions in electricity demand regardless of whether such reductions are cost-effective or how they would impact the State’s economy, *see id.* at 34,871-75. Requiring States to take these actions would be far outside of EPA’s statutory authority under the Clean Air Act.

Although EPA purports merely to set emission reduction targets that the States must meet, 79 Fed. Reg. at 34,892, EPA’s own findings reveal that those targets cannot be met solely by on-site emission reductions by coal-fired EGUs. States are on average required to reduce carbon emissions by 30% from 2005 levels by 2030 (notwithstanding any increases in demand),

79 Fed. Reg. at 34,832, but EPA predicts that coal-fired EGUs can achieve only a 6% reduction in emissions, a figure that, as explained below, likely overstates the emission reductions achievable through heat rate improvements. *See* Section VII.E.1., *infra*.⁵⁵ Thus, the only way that the targets can be met is for the States to restructure their electricity markets to prioritize the development and dispatch of EPA’s preferred energy sources and to require demand reduction. EPA finds no other “demonstrated” means of achieving emission reductions.

That EPA’s proposed rule would impermissibly intrude on core, sovereign State prerogatives protected by the Tenth Amendment is made most clear by the fact that the proposed rule would require States to enact a host of new laws. *Cf. Maryland*, 530 F.2d at 228 (“the right of [State] legislatures to pass, or not to pass, laws” is a core attribute of sovereignty). For example, the proposed rule notes that only 25 States currently have some form of law requiring a minimum percentage of retail electricity load to come from renewable sources. 79 Fed. Reg. at 34849. The proposal acknowledges that these “standards have been established via utility regulatory commissions, legislatures and citizen ballots.” *Id.* To comply with the proposed rule, the remaining States could be forced to enact RPSs, which would thus require action by State “utility regulatory commissions, legislatures [or] citizen ballots.” Further, even those States that already have RPSs may need to revise those standards to meet EPA’s prescribed targets, possibly by enacting new legislation. The same is true of State energy efficiency standards. While some States have adopted laws requiring certain efficiency standards, *see, e.g.*, CAL. PUB. UTIL. CODE § 454.5(a)(9)(C), many have not and would need to enact laws to do so. Plainly, then, the proposed rule is an attempt by “an agency of the United States to direct ... state legislature[s] to legislate.” *Maryland*, 530 F.2d at 228. Under the Tenth Amendment, the decision to enact a law lies with the State legislature, not unelected federal officials.

Moreover, the proposed rule would violate the Tenth Amendment even as to those States that would not need to enact new legislation to meet EPA’s prescribed targets. The Supreme Court made clear in *Printz* that commandeering State executive and regulatory authority is no less a Tenth Amendment violation than commandeering a State legislature. There, the government defended the challenged law by arguing that it did not require the States to make law or policy, but merely to execute the federal background-check program. *Printz*, 521 U.S. at 926-27. The Court held that it was not “compatible with [the States’] independence and autonomy that their officers be ‘dragooned’ ... into administering federal law.” *Id.* at 928; *see id.* at 932 (“where ... it is the whole *object* of the law to direct the functioning of the state executive,” the law violates “the very *principle* of separate state sovereignty”). Consequently, EPA can no more direct State PUCs or other regulatory bodies to enact its programs than it can require State legislatures to do so. EPA simply may not “command the States’ officers ... to administer or enforce” the proposed rule. *Id.* at 935; *see MCI Telecom. Corp. v. Illinois Bell Tel. Co.*, 222 F.3d 323, 343 (7th Cir. 2000) (the federal government “cannot ‘commandeer’ state regulatory agencies ... [by] forcing them to regulate”).

⁵⁵ Indeed, even under EPA’s most aggressive assumptions, coal-fired EGUs could only reduce emissions by 12 percent, *see* 79 Fed. Reg. at 34,859, a figure well short of EPA’s overall emission reduction target.

The anti-commandeering rule applies regardless of whether EPA would have the authority to administer its desired program directly. *New York*, 505 U.S. at 166. But here, EPA has no such authority. Through the proposed rule, EPA is seeking to do indirectly what it cannot do directly. *Cf. Altamonte Gas Transmission Co. v. FERC*, 92 F.3d 1239, 1248 (D.C. Cir. 1996). As explained in Section IX., *infra*, EPA has no authority, under Section 111(d) or any other statutory provision, to change the dispatch order of power plants, to mandate that power plants be utilized a certain percentage of time, to delay the retirement of nuclear plants, to require that a certain percentage of each State’s power be generated through solar and wind power, or to require that citizens reduce their demand for electricity. EPA cannot accomplish the same result by commandeering the States’ police powers and forcing the States to take steps that EPA could not take itself. And the fact that EPA could achieve these goals only by compelling States to implement Section 111(d) implementation plans confirms that the proposed rule violates the Tenth Amendment.

D. EPA Lacks Authority To Impose Different Standards On Each State

EPA’s proposal is also unlawful because it imposes dramatically different emission reductions obligations on each State. Section 111 is inherently a source-based regulatory program and, to the extent that EPA seeks to administer the program directly, it must treat similarly situated existing sources in the same manner, regardless of the State in which they are located. But, by conducting its BSER analysis and proposing emission reduction targets at a Statewide rather than source-specific level, EPA is proposing a system where affected EGUs may be subject to different standards based solely on the fact that they are located in different States. These problems are further exacerbated by EPA’s consideration of emission reductions that can be achieved by entities outside of the fossil fuel-fired EGU source categories subject to regulation under Section 111(b). Section 111(d) does not permit EPA or the States to impose standards of performance for existing sources that are unrelated to the facility itself and instead are based on the presence or absence of other electricity generators within the State.

First, the standards of performance to be established by States under Section 111(d) are intended to be source-based standards. The plain text of Section 111(d) directs States to “establish[] standards of performance *for any existing source* ... to which a standard of performance would apply *if such existing source* were a new source.” 42 U.S.C. § 7411(d)(1) (emphasis added). Further, the standard of performance must reflect the “best system of emission reduction” adequately demonstrated, *id.* § 7411(a), and, as describe in Section VII.A.1., *infra*, a “system of emission reduction” under Section 111 is inherently source-specific. EPA recognized this in its initial 1975 rulemaking to implement Section 111(d). There, EPA asserted that Congress intended the emission guidelines and standards of performance established under Section 111(d) to be technology-based. 40 Fed. Reg. at 53,342-43. A technology-based standard is inherently source-specific, and EPA tacitly acknowledged this while discussing States’ authority to impose more stringent standards: “EPA’s emission guidelines will reflect its judgment of the degree of control that can be attained by various classes of existing sources without unreasonable costs. Particular sources within a class may be able to achieve greater control without unreasonable costs.” *Id.* at 53,343. The question of whether or not a source or category of sources can achieve the level of control in an emission guideline only makes sense in the context of a source-specific approach.

Second, the “best system of emission reduction . . . adequately demonstrated” for an existing source or category of sources cannot be contingent on the existence (or capacity to construct) other, unrelated facilities that produce the same product. Yet, that is exactly what EPA has done here with respect to electricity generation. Under EPA’s proposed BSER analysis, the agency looks beyond the emissions controls that can be implemented by coal-fired EGUs and also considers the availability (or future availability) of other sources of electricity generation that could displace electricity generation from existing coal-fired EGUs. There is no statutory basis for such a State-wide approach. Neither the “integrated nature of the electricity system,” 79 Fed. Reg. at 34,836, nor the fact that States are directed to submit Statewide implementation plans creates a basis for EPA to deviate from Congress’ intent that systems of emission reduction be evaluated on a source-specific basis under Section 111(d). To the extent that there is any flexibility to look beyond individual facilities under Section 111(d), that flexibility belongs to the States as they develop implementation plans, not to EPA as it develops emissions guidelines. A central premise of any fair and reasonable regulatory scheme is that like sources should be treated alike. This is particularly true in the case of GHG emissions, where the pollutant at issue is truly global in nature and there are no localized impacts that could justify treating similar sources differently. Thus, after taking into account remaining useful life and other related factors, the standards of performance established under Section 111(d) should essentially apply uniformly to all existing fossil fuel-fired EGUs. EPA’s proposed emission reduction targets fail to meet this standard. For example, under EPA’s analysis, two identical coal-fired EGUs operating in neighboring States built at the same time using the same technology would be subject to different emissions control obligations under Section 111(d) based solely on the availability of competing natural gas, nuclear, and renewable energy in the State. For example, on an aggregate basis, coal-fired EGUs in Texas will be required to reduce their capacity by 50% in order to comply with the proposed emission reduction target as a result of the presence of underutilized NGCC facilities in the State.⁵⁶ In contrast, coal-fired EGUs in West Virginia will not need to reduce generation at all because there is no existing NGCC capacity available to replace it.⁵⁷ It is both arbitrary and capricious and contrary to Congress’ intent that virtually identical existing sources could be subject to such divergent emission control obligations.

Further, by imposing binding emission reduction targets on a Statewide rather than source-specific basis, EPA is inviting the States to impose inconsistent obligations on individual facilities in their implementation plans. EPA appears to take the position in the proposed rule that States will have complete discretion to impose emission reduction obligations solely on affected EGUs or on a broader range of affected facilities through a “portfolio” approach. Nowhere does EPA indicate that States must treat similarly situated EGUs in a similar fashion.

⁵⁶ EPA, Data File: Goal Computation –Appendix 1 and 2, *available at* <http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-technical-documents>.

⁵⁷ *Id.* Nevertheless, States such as West Virginia will still be impacted significantly by the rule. Not only will coal-fired EGUs struggle to achieve the six percent heat rate improvement included in EPA’s BSER analysis, *see* Section VII.E.1., *infra*, it also faces daunting renewable energy targets due to being placed in a region with States such as Maryland and Virginia that have significant potential for offshore wind development, *see* Section VII.E.4., *infra*.

Thus, for example, States could potentially impose more stringent emission limits on certain coal-fired EGUs in an attempt to dictate which facilities within a State will be forced to close. This is of particular concern in States that export significant amounts of electricity. By targeting companies that export significant portions of their generating capacity with larger emission reduction obligations, States could effectively export the costs of compliance to rate payers in neighboring States, while minimizing the in-State effects of the rule. An approach that shifts compliance costs to out-of-State rate payers would embody the type of economic protectionism that national pollution control programs are designed to avoid. Imposing source-specific standards of performance on affected EGUs would avoid the temptation for States to impose differing standards on similarly situated EGUs in an effort to protect their own residents and export the costs of complying with the rule.

Finally, by looking beyond the fence line at emission reductions that can be achieved through renewable energy generation and demand-side energy efficiency, EPA is, in effect, punishing early adopters by imposing more stringent emission reduction targets. EPA's emission reduction targets for both renewable energy and energy efficiency are based on regional or national targets, but also include growth projections that begin in 2017 and continue through 2030. For States that have already adopted and implemented such renewable and demand-side energy efficiency programs, the ramp up period is short, and their emission reduction targets are based on EPA's maximum values within a few years. In contrast, other States that have not yet implemented such programs will not be required to demonstrate full compliance with EPA's maximum values until much later, if at all. For example, both Missouri and Illinois are located in the North Central region and are assigned renewable energy targets of 15%. *See* TSD at 4-15, 4-17. However, Missouri is only obligated to increase its renewable capacity from 1% to 3% of Statewide generation, while Illinois must increase its renewable capacity by 5% (from 4% to 9%). *Id.* at 4-27. In other words, EPA is requiring more aggressive renewable energy expansion for States that have already shown leadership in promoting renewable energy.

VII. EPA'S PROPOSED STATE EMISSION REDUCTION TARGETS ARE NOT BASED ON A BEST SYSTEM OF EMISSION REDUCTION FOR EXISTING SOURCES AND VIOLATE THE CLEAN AIR ACT

Under Section 111, a "standard of performance" is defined as:

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.

42 U.S.C. § 7411(a). While no court has interpreted this definition in the context of Section 111(d), several cases have addressed standards of performance under Section 111(b). These cases are relevant for defining the scope of EPA's and the States' authority under Section 111(d).

An emission control technology is "adequately demonstrated" under Section 111 when it "has been shown to be reasonably reliable, reasonably efficient, and [it] can be expected to serve the interests of pollution control without becoming exorbitantly costly in an economic or

environmental way.” *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 433 (D.C. Cir. 1973). Under Section 111, EPA may “look[] toward what may fairly be projected for the regulated future, rather than the state of the art at present,” but these projections are necessarily constrained by the effective date by which the performance standards go into effect. *Portland Cement Ass’n v. Ruckelshaus*, 486 F.2d 375, 391-92 (D.C. Cir. 1973). Thus, standards of performance may not be based on emission control technologies that are “purely theoretical or experimental,” *Essex Chem.*, 486 F.2d at 434, nor “based on a ‘crystal ball’ inquiry.” *Portland Cement Ass’n*, 486 F.2d at 391; *see Costle*, 657 F.2d at 362 (emission limit could not be achievable based on test data from “non-lime/limestone processes” because they “are not widely available”).

In the proposed rule, EPA applies a BSER analysis that looks beyond the fence line of the fossil fuel-fired EGUs that are the subject of this rulemaking and seeks to incorporate emission reductions that it asserts can be achieved by shifting electricity generation to other sources or by reducing consumer demand for electricity. This “Building Block” approach is unlawful and contrary both to the plain meaning of Section 111 and the broader context of the Clean Air Act, which require a BSER analysis that is focused solely on the existing source that is subject to regulation under Section 111(d). Further, EPA cannot salvage its approach through an alternative BSER analysis that replaces the beyond the fence line emission reductions with mandatory reductions in coal-fired electricity generation.

A. EPA’s “Beyond The Fence Line” BSER Analysis Is Foreclosed By The Plain Language Of Section 111(d)

The plain and unambiguous language of Section 111(d) requires EPA and the States to take a source-specific approach when conducting a BSER analysis and establishing standards of performance. The source-specific nature of Section 111 standards of performance has been recognized by the courts and consistently applied by EPA in past Section 111(d) rulemakings. EPA’s proposed system-based approach that looks to entities beyond the regulated facilities is inconsistent with this past precedent, incompatible with the statutory provisions, and ultimately results in the regulation of a wide range of entities that are not existing fossil fuel-fired EGUs subject to Section 111(d).

1. The Plain Language of Section 111(d) Requires a Source-Based BSER Analysis

The plain language of Section 111(d) directs the States to “establish standards of performance *for any existing source* ... to which a standard of performance under this section would apply if such existing source were a new source.” 42 U.S.C. § 7411(d)(1) (emphasis added). Section 111 further defines a stationary source as “any building, structure, facility, or installation which emits or may emit an air pollutant.” *Id.* § 111(a). The statutory text here is clear. Standards of performance under Section 111(d) are not established in the aggregate for an entire sector of the United States’ economy. Instead, standards of performance must be established specifically “for any existing source.” The clear implication of this directive is that the standards of performance must be established on an individual basis for each class or category of existing sources and, therefore, must be limited to the types of actions that can be

implemented directly by an existing source within that class or category.⁵⁸ Likewise, the best system of emission reduction adequately demonstrated, which the standard of performance must reflect, must also be applied in a source-based manner. *See, e.g., Portland Cement Ass'n*, 486 F.2d at 391 (“The essential question was whether the technology would be available for installation in new plants.”).

The narrow source-based approach mandated by Congress in Section 111 has been explicitly recognized by the Courts. In *Asarco v. EPA*, 578 F.2d 319 (D.C. Cir. 1978), the court applied a narrow construction of the term “stationary source” under Section 111. There EPA sought to apply a “bubble concept” to existing stationary sources in a manner that would allow certain facilities to avoid regulation under Section 111(b) because emissions increases from one source within a facility could be offset by emission reductions from other sources in the same facility. *Id.* at 324. The court rejected EPA’s assertion that the Agency should be afforded discretion to define stationary sources and held that “[t]he regulations plainly indicate that EPA has attempted to change the basic unit to which NSPSs apply from a *single* building, structure, facility, or installation—the unit prescribed by statute—to a *combination* of such units. The agency has no discretion to rewrite the statute in this fashion.” *Id.* at 326-27 (emphasis in original). Thus, *ASARCO* confirms that individual stationary sources are the focal point of standards under Section 111, and that EPA lacks discretion to apply standards of performance or conduct BSEER analyses under Section 111 at a level beyond individual sources. Similarly, in *Alabama Power Co. v. Costle*, 636 F.2d 323, 397 (D.C. Cir. 1979), the court confirmed that under “the limited scope afforded the term ‘source’ in section 111(a)(3), however, EPA cannot treat contiguous and commonly owned units as a single source unless they fit within the four permissible statutory terms [of building, structure, facility, or installation].”

Furthermore, the Court has recognized in other contexts that the NSPS program and definition of source must be implemented in the specific context of that program. For example, the *Alabama Power* court held that under the Section 169 PSD program, “EPA has latitude to adopt definitions of the component terms of “source” that are different in scope than those that may be employed for NSPS and other clean air programs due to differences in the purpose and structure of the two programs.” *Id.* at 397-98. *ASARCO* and *Alabama Power* highlight the specific focus of Section 111 on individual facilities and prohibit EPA from claiming discretion to apply a BSEER analysis or to establish standards of performance under Section 111 at anything broader than a source-specific level.

2. EPA Has Consistently Applied Section 111(d) in a Source-Specific Context

In prior Section 111(d) rulemakings, EPA has consistently taken the position that BSEER analyses must be applied in a source-based manner that focuses primarily on individual sources that can be retrofitted with pollution control technology. When it issued implementing regulations for Section 111(d), EPA repeatedly emphasized that the emissions guidelines derived

⁵⁸⁵⁸ Indeed, a standard of performance cannot be “achievable” for an existing source, *see* 42 U.S.C. § 7411, if it cannot be implemented without assistance by other non-regulated entities in the electricity sector.

from EPA's BSER analysis must be technology-based. *See* 40 Fed. Reg. 53,542-44. In that context, it is clear that EPA interpreted Section 111(d) to require BSER analyses and emissions guidelines that were based on source-specific pollution control technologies. For example, EPA asserted that some systems of emission reduction may be excluded under Section 111(d) because "physical limitations may make installation of particular control systems impossible or unreasonably expensive." *Id.* at 53,344. EPA also contrasted "the cost of controlling existing facilities" with "those for controlling new sources." *Id.* at 53,341. Finally, EPA explained that "the degree of control reflected in EPA's emission guidelines will take into account the costs of retrofitting existing sources." *Id.* at 53,341. Nowhere in that rulemaking does EPA suggest that its emissions guidelines could be based on emission reductions undertaken by unrelated third parties or through reduced operation of affected facilities. Thus, only a source-based BSER analysis focused on pollution control technology would be consistent with the approach described by EPA in the 1975 rule's preamble.

Further, in Section 111(d) rulemakings for individual source categories, EPA has consistently applied a source-based BSER analysis that focused on specific pollution control technologies, sometimes supplemented by work practices that an existing source could implement on site to reduce its emissions of target pollutants. In fact, EPA has applied a technology-based, source-specific BSER analysis in every prior Section 111(d) rulemaking:⁵⁹

- *Sulfuric Acid Plants.* EPA established emission guidelines for sulfuric acid mist from existing sulfuric acid production units based on the emission reductions achievable by installing fiber mist eliminators. 41 Fed. Reg. 48,706, 48,706 (Nov. 4, 1976) ("The proposed sulfuric acid mist emission guideline of 0.25 gram acid mist per kilogram of acid produced (0.5 lb/ton) is based upon the degree of control achievable through the application of fiber mist eliminators to existing sulfuric acid production units.").
- *Phosphate Fertilizer Plants.* EPA established emission guidelines for fluoride emissions from existing phosphate fertilizer plants after concluding that retrofitting existing sources with spray-crossflow packed bed ("SCPB") scrubbers was the best system of emission reduction. 42 Fed. Reg. 12,022, 12,022 (Mar. 1, 1977).
- *Kraft Pulp Mills.* EPA established a series of emission guidelines for total reduced sulfur ("TRS") from a variety of sources at Kraft pulp mills that ranged from 5 to 25 ppm TRS. 44 Fed. Reg. 29,828, 29,829 (May 22, 1979). EPA explained in a separate guidance document that each emission guideline was based on pollution control technology that could be implemented directly by the existing sources. EPA, *Kraft Pulping: Control of TRS Emissions from Existing Mills at 10-4* (Mar. 1979) (listing best demonstrated control technique and the associated achievable TRS level for

⁵⁹ While EPA has also promulgated a number of rules for existing solid waste incineration units under Sections 111(d) and 129, EPA is required to apply a more stringent "maximum achievable control technology" standard under Section 129. *See* 42 U.S.C. § 7429 (2); (b)(1); 65 Fed. Reg. 75,338, 75,339 ("Under section 129, the NSPS and EG adopted for CISWI units must reflect maximum achievable control technology (MACT)."). As a result, those analyses are not relevant to the BSER standard at issue here.

recovery furnaces, digester systems, multiple-effect evaporator systems, lime kilns, smelt dissolving tanks, and condensate stripping systems). EPA did not establish emission guidelines for two other sources—brown stock washer systems and black liquor oxidation systems—after concluding that there were no pollution control techniques that were both cost effective and “demonstrated on an existing [source].” *Id.* at 10-12.

- *Primary Aluminum Plants.* EPA established emission guidelines for fluoride emissions from existing primary aluminum plants based on “effective collection of emissions, followed by efficient fluoride removal by dry scrubbers or wet scrubbers.” 45 Fed. Reg. 26,294, 26.294 (Apr. 17, 1980) (“[Emissions guidelines] are ... presented as average fluoride control efficiencies expected from the application of certain recommended control technologies that are applied as new retrofits to existing plants.”).
- *Municipal Solid Waste Landfills.* EPA established emission guidelines for methane and non-methane organic compounds (“NMOC”) based on the emission reductions achievable by installing a flare to combust emitted gases. 61 Fed. Reg. 9,905, 9,907 (“The [best demonstrated technology] control device is a combustion device capable of reducing NMOC emissions by 98 weight-percent.”).

Thus, in every past instance where EPA has established emissions guidelines under Section 111(d) using the BSER standard, it has relied exclusively on systems for emission reduction that can be implemented onsite by each existing source subject to the regulation. EPA’s past practice—some of which predates EPA’s implementing regulations for Section 111(d)—further confirms that the BSER analysis and emissions guidelines established under Section 111(d) must be source-based and rely solely on actions that can be undertaken on site by the affected facility.

3. EPA’s Proposed Expansion of BSER Is Unlawful

In a dramatic departure from its past precedent, EPA asserts for the first time that it can look beyond the fence line of affected facilities when it conducts a BSER analysis and incorporate emission reduction opportunities that can be implemented by unrelated third parties. EPA’s interpretation is unlawful, arbitrary, and capricious because EPA fails to provide a reasoned basis for changing its interpretation. *See, e.g., Jicarilla Apache Nation v. Dep’t of the Interior*, 613 F.3d 1112, 1119 (D.C. Cir. 2010) (“One of the core tenets of reasoned decisionmaking announced in *State Farm* is that an ‘agency changing its course ... is obligated to supply a reasoned analysis for the change.’” (alteration in original) (citations omitted)). Here, EPA fails to offer such a reasoned analysis.

EPA offers three reasons for expanding its BSER analysis to include Building Blocks 2, 3, and 4:

First, we determined that some strategies available in the other two groupings can support reduced CO₂ emissions from the fossil fuel-fired EGUs by significant amounts and at lower costs than some of the strategies in the first grouping. Second, we observed that strategies in all three groupings were already being

pursued by states and sources taking advantage of the integrated nature of the electricity system, at least in part for the purpose of reducing CO₂ emissions. Third, we were concerned that if measures from the first grouping that improve heat rates at coal-fired steam EGUs were implemented in isolation, without additional measures that encourage substitution of less carbon-intensive ways of providing electricity services for more carbon-intensive generation, the resulting increased efficiency of coal-fired steam units would provide incentives to operate those EGUs more, leading to smaller overall reductions in CO₂ emissions.

79 Fed. Reg. at 34,856. In essence, EPA is arguing that it can expand its BSER analysis to look beyond the fence line of individual facilities because doing so will result in greater reductions of CO₂ emissions than a source-based approach alone could achieve. But even if that were true as a factual matter—an assumption that the Associations contest—these results-oriented reasons offer no insight as to why such an approach is legally permissible under Section 111(d). As a result, these observations are irrelevant to the legal question at hand and cannot provide a reasoned basis for EPA to change its interpretation of the meaning of standards of performance under Section 111(d).

EPA ultimately goes on to claim that it has discretion to adopt a beyond the fence line approach to BSER based on an expansive interpretation of the word “system” that is entirely divorced from the context of Section 111. Specifically, EPA asserts that the word “system” was not defined by Congress and should be interpreted to mean “[a] set of things working together as parts of a mechanism or interconnecting network.” *Id.* at 34,885. Under that interpretation, EPA asserts that it can consider all four Building Blocks in its BSER analysis because each is part of the “interconnected and integrated ... electricity system.” *Id.* at 34,881. EPA’s argument misses the mark. First, under the plain meaning of the statute, the system of emission reduction must be something that can be applied to the “existing source.” *See* 42 U.S.C. § 7411(d)(1)(A). Under Section 111, the definition of an existing source is limited to a “building, structure, facility or installation which emits or may emit any air pollutant.” *Id.* § 7411(a)(3), (6). EPA’s proposed “system” of emission reduction goes well beyond existing fossil fuel-fired EGUs and instead encompasses the entire electricity sector. The restructuring of the entire electricity sector is something that must be accomplished by State legislative and regulatory action and cannot be applied to an existing fossil fuel-fired EGU as Section 111(d) contemplates. Second, the operative term in the definition of standard of performance in Section 111(a)(1) is not “system,” but “system of emission reduction.” Thus, even under EPA’s interpretation, Section 111 requires EPA or the States to identify a set of things working together as parts of a mechanism or interconnecting network *to reduce emissions*. The four Building Blocks identified by EPA do not meet this standard because they are a set of things working together as parts of a mechanism or interconnecting network *to generate electricity*. The mere fact that shifting generation from coal to other energy sources has an effect on net CO₂ emissions from the electricity sector does not make those other energy sources “pollution prevention measures” for coal-fired EGUs. *See id.* at 34,886.

Further, EPA’s interpretation of “system” under Section 111(d) also allows it to unlawfully shift the focus of regulation to other entities that are not “existing sources” “to which a standard of performance under [Section 111(b)] would apply.” 42 U.S.C. § 7411(d). Indeed, because the primary focus of the proposed rule is not managing pollution, but rather managing

electricity dispatch and consumption, fossil fuel-fired EGUs are not the sole focus of the rule. Instead, in key respects, the proposed regulation is addressed to State governmental agencies and transmission operators that manage the broader dispatch and flow of electricity, along with retail consumers of electricity who dictate overall demand. For example, increased dispatch of natural gas can only occur if State PUCs and grid operators mandate it.⁶⁰ Mandating the construction of new renewable power plants and preservation of “at risk” nuclear plants capable of making up for the diminished coal generation requires action by State legislatures and regulatory agencies. None of these entities emit any air pollutant subject to regulation under Section 111(d) and, as a result, cannot be considered “stationary sources” within the context of Section 111. Further, even the nuclear energy facilities that EPA would prohibit from closing and the renewable energy facilities that EPA would require to be built are classified as “zero-emission” under the proposed rule⁶¹ and, as a result, are also outside the scope of Section 111, if not the Clean Air Act entirely. A rule that seeks to hold regulated entities—here fossil fuel-fired EGUs—liable and accountable for these third party entities is contrary to the plain meaning of Section 111.

In contrast to EPA’s interpretation, a “system” of emission reduction must be read in a limited fashion that focuses on emission reductions that can take place at a specific existing facility. For example, a “system” of emission reduction might incorporate multiple emission control technologies or direct sources to adopt best practices along with emissions controls. EPA took this approach when it established emissions guidelines for lime kilns located at Kraft Paper Mills.⁶² There, EPA established an emission guideline of 20 ppm of TRS over a 12-hour average.⁶³ To meet this guideline, EPA explained that facilities would need to “maintain[] the proper oxygen level and cold-end temperature, and use[] water that does not contain dissolved sulfides in the particulate control scrubber,” along with additional filtration and clarifier capacity and additional fan capacity.⁶⁴ Individually, these emission control technologies and best practices could not achieve the emission guidelines established by EPA, but together, they formed a system of emission reduction that could be employed at each existing source to meet the 20 ppm emissions target. In the same manner, the heat rate improvements—including best practices and equipment upgrades—identified by EPA in Building Block 1 arguably form a “system” of emission reduction that together reduce CO₂ emissions from existing coal-fired EGUs (although, for reasons described below, EPA’s specific assumptions in Block 1 are arbitrary and capricious). Thus, when considered within the broader context of Section 111, the

⁶⁰ Pursuant to the FPA, FERC approval may also be required for States and RTOs to deviate from existing least-cost dispatching. *See* 16 U.S.C. §§ 824d, 824e.

⁶¹ EPA’s BSER analysis treats all renewable energy as zero-emission by accounting for its generating capacity, but not any associated emissions, when calculating State emission reduction targets.

⁶² *See* EPA, Kraft Pulping: Control of TRS Emissions From Existing Mills, EPA-450/2-78-003b (March 1979).

⁶³ *Id.* at 10-10.

⁶⁴ *Id.*

“system” of emission reductions refers to the range of options that can be implemented by an existing source to reduce its emissions, not “anything that reduces the emissions of affected sources” regardless of the entity that undertakes the emission reduction. 79 Fed. Reg. at 34,886.

EPA’s approach is also unsupported by the Clean Air Act’s legislative history. In 1970, the definition of “standard of performance” was the same as it is now. In 1977, however, Congress revised the definition; among other changes, new source standards were based on “the best *technological* system of *continuous* emission reduction,” and existing source standards were based on “the best system of *continuous* emission reduction.” Clean Air Act Amendments of 1977, Pub. L. No. 95-95, § 109, 91 Stat. 685, 699-700 (1977) (emphasis added). The 1990 Amendments restored the original 1970 definition. See 42 U.S.C. § 7411(a)(1). EPA has previously argued that “Congress’ decision not to include the terms ‘technological’ and ‘continuous’ in the post-1990 section 111(a) definition of standard of performance was at least to some extent deliberate.” Final Brief of Respondent, *New Jersey v. EPA*, 703 F.3d 110 (D.C. Cir. 2012) (No. 05-1097), 2007 WL 3231264, at *127-28. But the legislative history belies any claim that the omission of these terms reflects a congressional intent to broaden EPA’s authority. The 1977 insertion of these terms was prompted by a controversy over whether power plants could satisfy the applicable standards simply by switching to low-sulfur fuel; the addition of “technological” was intended merely to make clear “that adequately demonstrated *technology* is to be the basis of the standard, not merely reliance on use of untreated fuels.” H.R. Rep. 95-294 at 11, 1977 U.S.C.C.A.N. at 1088 (emphasis added); see also *Wisc. Elec. Power Co. v. Reilly*, 893 F.2d 901, 919 (7th Cir. 1990). In turn, the removal of “technological” in 1990 was intended simply to restore the pre-1977 status quo, under which sources had more flexibility in how to comply with the governing standards. EPA itself acknowledged at the time that “the [1990] amendments seem to be designed to permit more choice and flexibility in how companies meet the substantive requirements [of Section 111].” 136 Cong. Rec. S16895-01 (1990). And Congress was well aware that the standards were always focused on at-the-unit technology, even under the 1970 definition, which did not contain the word “technological.” See *id.* (“The 1970 Amendments to the Act required EPA to promulgate *technology-based* new source performance standards” (emphasis added)). Thus, the absence of the word “technological” from the current definition does not give EPA a mandate to regulate electricity dispatch by States, require construction of renewable energy, set standards for nuclear retirement, and manage retail demand.

B. EPA’s Beyond The Fence Line Approach Is Incompatible With The Structure Of The Clean Air Act

While the plain language of Section 111(d) dictates that BSER analyses and standards of performance must be source-specific, this approach is further supported by the broader context of the Clean Air Act. When evaluating the meaning of the Clean Air Act New Source Review provisions, the Supreme Court recently confirmed that a “reasonable statutory interpretation must account for both ‘the specific context in which ... language is used’ and ‘the broader context of the statute as a whole.’” *UARG*, 134 S. Ct. at 2442 (quoting *Robinson v. Shell Oil Co.*, 519 U. S. 337, 341 (1997)). Thus, even if a court were to find some portion of Section 111 to be ambiguous, the provisions at issue could be “clarified by the remainder of the statutory scheme ... because only one of the permissible meanings produces a substantive effect that is compatible with the rest of the law.” *United Sav. Ass’n of Tex.*, 484 U. S. at 371. Thus,

identifying a single ambiguous term in a statute—as EPA purports to do with the word “system”—does not give the agency *carte blanche* to adopt any interpretation that suits its purposes. *UARG*, 134 S. Ct. at 2442 (“Thus, an agency interpretation that is ‘inconsisten[t] with the design and structure of the statute as a whole’ ... does not merit deference.” (quoting *University of Tex. Southwestern Medical Center v. Nassar*, 133 S. Ct. 2517, 2529 (2013))).

First, as explained in Section IV., *supra*, EPA can only establish standards of performance for existing sources under Section 111(d) after it makes a determination that the source category “causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare” and then establishes standards of performance for new sources in that source category. 42 U.S.C. § 7411(b), (d). Here, EPA has neither made an endangerment determination nor established standards of performance under Section 111(b) for any of the entities that it seeks to regulate through a beyond the fence line approach. Thus, by basing its BSER analysis on actions that can only be accomplished by these entities, EPA is effectively incorporating them into the regulated source category. As EPA recognizes, opportunities to reduce CO₂ emissions at existing coal-fired EGUs are limited, and regulatory obligations must be imposed on other entities in order to achieve the proposed emission reduction targets. Thus, by expanding its BSER analysis beyond the fence line and authorizing a “portfolio approach” for compliance,⁶⁵ EPA’s proposal would ensure that sources other than fossil fuel-fired EGUs can—and almost certainly will—be subject to legally enforceable compliance obligations.

Beyond the fact that EPA implicitly expanded its BSER analysis to include categories for which it has not established standards of performance for CO₂ emissions under Section 111(b), it is doubtful that EPA could do so in any event. Under Section 111, EPA is only authorized to establish standards of performance for “stationary sources” which are defined as “building[s], structure[s], facilit[ies], or installation[s] which emit or may emit any air pollutant,” 42 U.S.C. § 7411(a)(3), that cause or contribute significantly to the endangerment of human health or the environment, *id.* § 7411(b). Contrary to this important limitation on EPA’s authority under Section 111, the Agency includes nuclear energy, renewable energy, and electricity consumers in its BSER analysis precisely because they do *not* emit CO₂ (or any other identified air pollutant). EPA includes nuclear and renewable energy in its BSER analysis because they are “lower-emitting EGUs and zero-emitting energy sources” that can be dispatched instead of fossil fuel-fired EGUs. *See* 79 Fed. Reg. at 34,835. In fact, EPA treats all nuclear and renewable energy sources included in Building Block 3 as zero-emission sources by including their generating capacity in the State emissions rate target calculation without including any associated CO₂ emissions. *See* EPA, Goal Computation Technical Support Document at 14-16 (June 2014). Likewise, EPA includes demand-side energy efficiency in Building Block 4 not because electricity is produced but because less could be consumed. Thus, the fact that the Clean Air Act prohibits EPA from regulating these entities directly under Section 111 is strong evidence that Congress did not intend EPA to regulate them indirectly by adopting an interpretation of BSER that allows EPA to look beyond the fence line.

⁶⁵ As discussed in Section VIII., *infra*, imposing binding legal obligations on entities other than fossil fuel-fired EGUs is unlawful.

Second, as explained in Section V., *supra*, Sections 111(b) and 111(d) are inextricably tied, and EPA must interpret key regulatory terms, such as “standard of performance” and “best system of emission reduction ... adequately demonstrated” in the same manner under each provision. This is particularly true in the context of defining the source category that is the subject of a standard of performance. Thus, the source category regulated under Section 111(b) must serve as the starting point for regulation under Section 111(d), with the caveat that EPA is authorized to create subcategories where necessary to address differences between classes of facilities. *See* 42 U.S.C. § 7411(b) (“The Administrator may distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing such standards.”). Indeed, relying on this language, EPA explained that further subcategorization may be appropriate under Section 111(d). 40 Fed. Reg. at 53,341 (“Thus while there may be only one standard of performance for new sources of designated pollutants, there may be several emission guidelines specified for designated facilities based on plant configuration, size, and other factors peculiar to existing facilities.”). Here, the broader context of the Clean Air Act suggests that EPA’s authority to create subcategories of sources under Section 111 is a one-way ratchet. There is no corresponding authority in the text of Section 111 that permits EPA to aggregate diverse classes of sources into mega-categories for purposes of regulation. As a result, even EPA’s proposal to conduct a single BSER analysis for all fossil fuel-fired EGUs is unlawful.

In the past, EPA has relied on its authority to create subcategories for fossil fuel-fired EGUs under Section 111. EPA initially regulated all fossil fuel-fired EGUs under a single source category, Subpart D. *See, e.g.*, 79 Fed. Reg. at 1,454. EPA later carved out fossil fuel-fired combustion turbines, first in Subpart GG and later in Subpart KKKK, due to differences between these sources and steam generating EGUs. *Id.* Such subcategorization was appropriate and consistent with EPA’s authority under Section 111. Having narrowed those source categories, EPA cannot now expand them to include coal- and natural gas-fired EGUs in a single source category. In fact, EPA recently recognized that doing so is unlawful when it withdrew its initial proposal to regulate GHG emissions from new fossil fuel-fired EGUs as part of a single source category. In its initial 2012 proposal, EPA announced plans to combine Subparts Da and KKKK into a single source category that would apply to all fossil fuel-fired EGUs. *See* 77 Fed. Reg. 22,392. EPA based its proposal on the assumption that new electricity generating capacity was essentially fungible because coal- and natural gas-fired EGUs “perform the same essential function” and because new sources “have options in selecting their design” in order to “readily comply with the proposed emission standards by choosing to construct a NGCC facility.” 77 Fed. Reg. at 22,411. As a result, EPA concluded in its BSER analysis that NGCC technology was the best system of emission reduction for all newly constructed fossil fuel-fired EGUs, meaning that proposed coal-fired EGUs would have to be transformed into natural gas-fired EGUs to comply with the proposed standards of performance.

In response to public comments challenging EPA’s authority to mandate the transition from coal to natural gas, EPA withdrew the 2012 proposal. *See* 79 Fed. Reg. 1,352. In its place, EPA issued a new proposal that appropriately treated coal- and natural gas-fired EGUs as separate source categories and conducted separate BSER analyses for each. 79 Fed. Reg. at 1,432-33. EPA noted that additional progress on several new coal-fired EGUs, as well as the potential for changes in market prices for coal and natural gas suggested that coal would remain a viable fuel source for new fossil fuel-fired EGUs, and on that basis determined that coal-fired EGUs should be evaluated independently under Section 111(b) and assigned a different standard

of performance. *Id.* at 1,434. In other words, because both coal and natural gas-fired EGUs remained viable options for new power generation, EPA determined that each should be subjected to its own BSER analysis and assigned a standard of performance based on the systems of emission reduction available to each source category.⁶⁶ In light of the inextricable ties between Sections 111(b) and 111(d), EPA cannot take the opposite approach here and apply a single BSER analysis for all fossil fuel-fired EGUs.

Third, standards of performance under Section 111 set a floor for BACT in the PSD program. *See* 42 U.S.C. § 7479(3) (“In no event shall application of ‘best available control technology’ result in emissions of any pollutants which will exceed the emission allowed by any applicable standard of performance established pursuant to Section 7411 ... of this title.”). This is because the “best available control technology” should be at least as stringent as the best system of emission reductions” that takes account of cost-effectiveness. The PSD program results in permit conditions that are imposed directly on a specific new or modified facility and, therefore, are necessarily source-based. The fact that Congress elected to make applicable standards of performance under Section 111 the “floor” for BACT determinations suggests that the BSER analyses used to develop such standards must also be source-based. Indeed, applying EPA’s beyond the fence line BSER analysis as the BACT floor would produce absurd results. In the proposed rule, EPA candidly acknowledges that existing coal-fired EGUs cannot achieve the proposed emission reduction targets. 79 Fed. Reg. at 34,901 (“Under this approach, the emission limits enforceable against the affected EGUs would not, on their own, assure, or be required to assure, achievement of the emission performance level.”). Yet, because standards of performance under Section 111(d) may be applied as a BACT floor if an existing source triggers PSD permitting obligations, permitting authorities would then be obligated to apply as a “best *available* control technology,” an emissions limit that EPA acknowledges cannot be achieved by control technology available to the facility. Again, placing Section 111 within the broader context of the entire Clean Air Act demonstrates that Congress intended BSER to be applied in a source-specific manner.

Fourth, important differences between Section 111’s BSER analysis and other regulatory approaches included in the Clean Air Act demonstrate that BSER must be applied in a source-specific manner and cannot take into consideration sources that are not part of the regulated source category. EPA asserts in the proposed rule that it can look beyond the fence line when conducting a BSER analysis because “in the area of pollution control, State governments and the federal government have repeatedly taken advantage of the integrated nature of the electricity system when designing programs to allow the industry to meet the pollution control objectives in a least cost manner.” *Id.* at 34,880. However, EPA fails to explain how the programs it

⁶⁶ As explained in their comments on the proposed NSPS for new sources under Section 111(b), the Associations support EPA’s decision to establish separate source categories for coal and natural-gas-fired EGUs, but disagree with EPA’s ultimate conclusion that partial carbon capture and storage is an adequately demonstrated and cost effective system of emission reduction for coal-fired EGUs.

identifies are relevant to its interpretation of Section 111(d).⁶⁷ The cap and trade program established by Congress in Title IV offers no support for EPA's assertion that a Section 111(d) BSER analysis can be based on the electricity system as a whole. Indeed, the fact that Congress had to amend the Clean Air Act to permit such a cap and trade program affirms that the authority to regulate the electricity system as a whole is not inherent in the Clean Air Act and instead should be limited to those sections where it is specifically authorized by Congress. Likewise, EPA's reliance on the Ozone Transport Commission NOx Budget Program, the NOx SIP Call NOx Budget Trading Program, and the Clean Air Transport Rule is also misplaced because those programs all address emissions control under the NAAQS program. EPA has acknowledged that the NAAQS program is fundamentally different from Section 111(d) because it is based on health-based standards rather than technology-based standards. 40 Fed. Reg. 53,343 ("For all of these reasons, EPA believes that Congress intended a technology-based approach [for Section 111(d)] rather than one based directly on protection of health and welfare."). Under the NAAQS program, EPA sets ambient air quality standards that must be met collectively by all sources within a region. Establishing implementation plans under those circumstances necessarily involves tradeoffs between controlling emissions from different sources and even different sectors in a region. The fact that States evaluate electricity generation comprehensively in order to meet health-based standards offers no support for EPA's assertion that it can take such a comprehensive approach when establishing technology-based standards under Section 111(d).

C. Any Ambiguity In Section 111(d) Cannot Be Used By EPA To Regulate The Entire Electricity Sector

To the extent that Section 111 leaves any ambiguity with respect to the content of a BSER analysis, that ambiguity cannot be used to expand the scope of EPA's regulatory authority in an unprecedented manner. First, the Supreme Court has made clear that Congress must "speak clearly" if it intends to give an agency "an unheralded power to regulate a significant portion of the American economy." *UARG v. EPA*, 134 S. Ct. at 244. Thus, "[w]hen an agency claims to discover in a long-extant statute an unheralded power to regulate 'a significant portion of the American economy,' ... we typically greet its announcement with a measure of skepticism." *Id.* (quoting *Brown & Williamson*, 529 U.S. at 159). Here, EPA is proposing a new interpretation of "best system of emission reduction ... adequately demonstrated" that allows it to look beyond the fossil fuel-fired EGUs in the regulated source categories and instead assume regulatory control over the entire energy generation and distribution sectors. Given the vast economic and political significance of the sectors that EPA now seeks to regulate, the authority to do so must be based on a clear, rather than ambiguous, delegation of power. *See id.*; *MCI Telecommunications Corp. v. American Telephone & Telegraph Co.*, 512 U. S. 218, 231 (1994); *Industrial Union Dept., AFL-CIO v. American Petroleum Institute*, 448 U. S. 607, 645-646 (1980) (plurality opinion).

⁶⁷ To the extent this argument has any validity, it suggests that affected EGUs should have flexibility to meet standards of performance in a least-cost manner at the implementation stage. *See* Section XIV.A., *infra*. It is wholly irrelevant to the BSER analysis on which those standards of performance are based.

Second, the courts have also made clear that ambiguous statutory language is not sufficient to authorize an agency to regulate an area that has been traditionally subject to State regulatory authority. *See Am. Bar Ass'n*, 430 F.3d at 472 (finding it unreasonable for federal agency to regulate area traditionally subject to State regulation when Congress has not spoken in clear terms). As explained in Section VI.B., *supra*, the FPA creates a division of responsibility between the States and the federal government that reserves to the States jurisdiction “over facilities used for the generation of electric energy or over facilities used in local distribution or only for the transmission of electric energy in intrastate commerce.” 16 U.S.C. § 824(b)(1). In contrast, “[f]ederal regulation ... extend[s] only to those matters which are *not* subject to regulation by the States.” *Id.* § 824(a) (emphasis added); *see Ark. Elec. Co-op.*, 461 U.S. at 377-78; *S. Cal. Edison Co.*, 376 U.S. at 215-16. Courts applying the FPA and the other federal energy statutes consistently conclude that States retain “traditional responsibility in the field of regulating electrical utilities for determining questions of need, reliability, cost and other related state concerns.” *Pac. Gas & Elec. Co.*, 461 U.S. at 205; *see also New York*, 535 U.S. at 20 (“FERC’s jurisdiction over the sale of power has been specifically confined to the wholesale market.” (emphasis omitted)); *Niagara Mohawk Power Corp.*, 452 F.3d at 824 (“States retain jurisdiction over retail sales of electricity and over local distribution facilities.”); *Duke Energy Trading & Mktg.*, 267 F.3d at 1056 (“Retail sales of electricity ... are within the exclusive jurisdiction of the States ...”). Thus, it would be wholly inappropriate for EPA to rely on a purportedly ambiguous environmental provision to claim authority over electricity markets that Congress has even expressly denied FERC.

Third, EPA’s interpretation of Section 111(d) must be rejected because it would interfere with the State’s sovereign authority—indeed, going as far as requiring States to enact new laws to implement EPA’s requirements. *See* Section II.A.1., *supra*. State regulation of electricity generation is “one of the most important functions traditionally associated with the police powers of the States.” *Arkansas Elec. Coop.*, 461 U.S. at 377. EPA will be presumed to have authority to “reach into areas of State sovereignty” only where Congress is “unmistakably clear.” *Will*, 491 U.S. at 65; *Gregory*, 501 U.S. at 461; *City of Abilene v. FCC*, 164 F.3d 49, 52 (1999). Here, there is no “plain statement” by Congress that it intended EPA to have authority to interfere with State sovereign authority over electricity markets. To the contrary, Congress expressly provided that States should determine performance standards in the first instance and that the States had substantial flexibility to account for the economic impact such standards would have on existing sources. *See* Section VI.A., *supra*.

D. Requiring An Existing Source To Cease Operations Is Not A System Of Emission Reduction

Finally, EPA cannot solve its flawed and unlawful BSER analysis by suggesting, in the alternative, that Building Blocks 2-4 are not technically part of the BSER analysis. *See* 79 Fed. Reg. at 34,889. EPA’s alternative BSER analysis combines the heat rate improvements in Building Block 1 with “the reduction of affected fossil fuel-fired EGUs’ mass emissions achievable through reductions in generation of specified amounts from those EGUs.” *Id.* Those “specified amounts” are equivalent to the amount of electricity generation that can be shifted to other electricity sources as identified in Building Blocks 2 and 3 or avoided as identified in Building Block 4. Even if this sleight of hand could be viewed as technically avoiding beyond the fence line emission reductions, it is no more lawful because it relies on reduced operation as

a primary means of emission reduction.⁶⁸ But a system-wide mandate to reduce electricity generation from coal-fired EGUs—primarily by forcing the retirement of individual units—cannot constitute BSER for existing sources. As an initial matter, it is patently unreasonable to suggest that a State-wide mandate to reduce coal-fired generating capacity by a specified amount, *id.* at 34,889, will be applied uniformly to all coal-fired EGUs operating in a State. Coal-fired EGUs are most viable as baseload electricity providers and operate most efficiently from both an economical and environmental perspective when they operate as close as possible to full capacity. A uniform 24% reduction in generating capacity⁶⁹ would threaten the economic viability of many units and would also have the perverse effect of negating many of the heat rate improvements that EPA relies on in Building Block 1. *See* Section VII.E.1., *infra*. Instead, mandatory reductions in electricity generation from coal would almost certainly result in the closure of a significant portion of the existing coal-fired EGU fleet. Indeed, this is a virtual certainty in the eleven States where EPA projects that coal-fired electricity generation will cease entirely.⁷⁰ Further, EPA’s own projections electricity generation in 2020 show that reductions in coal-fired electricity generation will be accomplished largely by plant retirements, as coal-fired electricity generating capacity will be reduced by an additional 49 GW in addition to what is required by MATS and other existing EPA regulations while the per unit capacity factor will actually increase.⁷¹ Thus, in evaluating the legality and reasonableness of EPA’s alternative BSER analysis, the relevant question is not whether EPA can mandate reduced operation, but whether EPA can mandate the closure of existing sources as a system of emission reduction for those sources.

First, applying BSER in a manner that mandates the retirement of existing facilities is fundamentally incompatible with the structure and intent of Section 111(d). Simply put, closing a facility cannot be considered a “best system of emission reduction ... adequately

⁶⁸ Indeed, regardless of which formulation of the BSER analysis EPA relies on, the effect is the same and requires a steep reduction in electricity generation from coal by substituting electricity generation from the sources identified in Building Blocks 2-4. Therefore, the arguments raised here apply equally to EPA’s primary BSER analysis that formally includes all four Building Blocks.

⁶⁹ According to EPA’s Technical Support Documents, application of Building Blocks 2-4 will reduce nationwide electricity generation from coal by 24%. Data taken from EPA, Data File: Goal Computation –Appendix 1 and 2 and EPA, Goal Computation Technical Support Document, *available at* <http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-technical-documents>.

⁷⁰ According to EPA’s supporting data, coal-fired electricity generation will cease entirely in Alaska, Arizona, California, Connecticut, Massachusetts, Mississippi, Nevada, New Hampshire, New Jersey, Oregon, and Washington. *Id.*

⁷¹ EPA, RIA at 3-32.

demonstrated” for that facility.⁷² Section 111(d)’s requirement that States establish standards of performance for existing sources by applying the BSER analysis only makes sense if the existing source continues operating after it is regulated and is capable of achieving the standard of performance. Indeed, Congress’ intent that existing sources continue operating after regulation under Section 111(d) is further supported by its requirement that States (and EPA) take into account other factors, including the remaining useful life of existing sources, when setting standards of performance. 42 U.S.C. § 7411(d)(1), (2). This obligation makes clear that, in the face of a potential facility closure, it is the standard of performance, not the facility, that must yield. This is particularly true with respect to coal-fired EGUs, as the legislative history of Section 111 shows that Congress clearly both understood and intended that coal would continue to be a viable fuel for source categories covered by NSPS standards. *See, e.g.*, H. Rep. No. 95-294 at 192 (“The committee has designed this section and the entire bill, to encourage and facilitate the increased use of coal....”).

Second, by relying on Section 111(d) to mandate the closure of a significant portion of the coal-fired EGU fleet, EPA would be exceeding its delegated authority by making energy policy rather than environmental policy. It is untenable to suggest that, by enacting Section 111(d), Congress intended to give EPA authority over electricity generation, dispatch and consumption. As the Supreme Court recently admonished, “[w]hen an agency claims to discover a long-extant and unheralded power to regulate ‘a significant portion of the American economy’ ... we typically greet its announcement with a measure of skepticism.” *UARG*, 134 S.Ct. at 2444 (quoting *Brown & Williamson*, 529 U.S. at 159). Here, that skepticism is most certainly warranted. Not only did Congress express an intent that EPA’s implementation of Section 111 would promote rather than eliminate coal-fired electricity generation, it has affirmatively recognized that the power to make basic decisions regarding fuel types in electricity generation belongs to the States and not to federal agencies. Thus, as explained in Sections VI.B. and C., *supra*, Congress effectively has prohibited EPA from mandating the retirement of existing coal-fired EGUs and their replacement with alternative energy sources.

Third, EPA cannot rely on other, arguably broader provisions in the Clean Air Act to expand its authority under Section 111(d). EPA’s reliance on the use of reduced operation or facility retirement as a means of complying with a national ambient air quality standard is misplaced. *See* 79 Fed. Reg. at 34,889; Legal Memo at 83. As EPA has explained, 40 Fed. Reg. at 53,343, Section 111 standards of performance are technology-based and differ from the health-based NAAQS that essentially set a cap on the total emissions for all sources within a region. Because a NAAQS sets a fixed ambient air quality standard that must be collectively achieved by all sources in a given region, it differs from the source-specific BSER analysis that must be applied to set performance standards for existing sources under Section 111(d). EPA’s reliance on the legislative history of Section 112 is equally misguided. *See* EPA, Legal Memo at 83. While technology-based in the first instance, Section 112 applies a more stringent MACT standard than the BSER standard applied under Section 111. *See* 42 U.S.C. § 7412(d)(2). For existing sources, EPA is required to apply that standard in a rigid and mechanical way by

⁷² Indeed, if Section 111(d) permitted EPA to mandate the closure of facilities, it is interesting that mandated closures were not applied as BSER in past 111(d) rulemakings. Regardless of the source category, ceasing operations completely will always maximize emission reductions.

calculating “the average emission limitation achieved by the best performing 12 percent of the existing sources.” *Id.* § 7412(d)(3). Courts have held that EPA lacks the discretion to deviate from this formula to address specific challenges faced by individual sources. *See Cement Kiln Recycling Coalition v. EPA*, 255 F.3d 855, 880 (D.C. Cir. 2001) (“EPA may not deviate from section 7412(d)(3)’s requirement that floors reflect what the best performers actually achieve by claiming that floors must be achievable by all sources using MACT technology.”). In contrast to this rigidity, Section 111(d) directs States to take a flexible approach in setting standards of performance that permits the application of less stringent standards of performance based on source-specific challenges. *See* 42 U.S.C. § 7411(d)(1). Again, these important differences suggest that reduced operations or forced retirements are not permitted as standards of performance under Section 111(d).

Finally, EPA seeks to justify the rule by asserting that “reduced generation by higher-emitting sources is one of the compliance options available to and used by EGUs to comply with the Clean Air Act acid rain program in CAA Title IV, as well as the transport rules that we refer to as the NO_x SIP Call and the Clean Air Interstate Rule (CAIR).” 79 Fed. Reg. at 34,889 (footnotes omitted). Here EPA fails to recognize the critical difference between standard setting and compliance. As the Associations explain more fully in Section XIV.A., *infra*, they fully support flexible compliance options that allow regulated entities to engage in voluntary programs to identify least-cost options—including the option of reduced generation—for complying with emission reduction goals. However, in the programs described by EPA, reduced generation was an option available for compliance; it was not a factor used to set the emissions limits established for those trading programs. Thus, there is no basis for EPA to rely on those programs in order to support the inclusion of reduced generation at the standard setting stage. Thus, EPA has failed to identify any precedent within the Clean Air Act that would allow it to mandate the retirement of coal-fired EGUs when establishing standards of performance under Section 111(d).

E. EPA’s BSER Analysis Is Arbitrary And Capricious

Beyond the legal errors in EPA’s decision to look beyond the fence line, EPA’s BSER analysis is arbitrary and capricious. By essentially treating each Building Block separately and in isolation, EPA fails to adequately account for many of the practical challenges that will be faced by the States and facilities that must try to achieve these aggressive emission reduction goals collectively, within the constraints of existing electricity generation and transmission systems. Further, even with respect to individual Building Blocks in isolation, EPA’s decision to conduct its BSER analysis through what is essentially a uniform national approach arbitrarily masks a number of State-specific issues that will preclude individual States from achieving the aggressive targets set by EPA, and the BSER analysis is therefore arbitrary and capricious as applied to those States.

Further, EPA’s assumptions regarding electricity generation, dispatching, and efficiency that form the basis of its Building Block approach would not be afforded deference during judicial review because management of the electric generation and transmission system is outside of EPA’s environmental expertise. *See* Section IX., *infra* (describing EPA’s lack of authority to regulate electricity generation and transmission). As the courts have repeatedly explained, “‘practical agency expertise is one of the principle foundations behind *Chevron* deference.’ ... Absent congressional delegation, if an agency has promulgated a regulation

outside the scope of its specialized knowledge, courts will not defer to it.” *Murphy Exploration & Prod. Co. v. U.S. Dep’t of the Interior*, 252 F.3d 473, 479 (D.C. Cir. 2001) (quoting *Pension Benefit Guar. Corp. v. LTV Corp.*, 496 U.S. 633, 651-52 (1990)); see also *Gonzales v. Oregon*, 546 U.S. 243, 269 (2006) (“The deference here is tempered by the Attorney General’s lack of expertise in this area and the apparent absence of any consultation with anyone outside the Department of Justice who might aid in a reasoned judgment.”); *Prof’l Reactor Operator Soc’y v. NRC*, 939 F.2d 1047, 1051 (D.C. Cir. 1991).

The following sections will identify key deficiencies in EPA’s assessment of each building block, followed by a number of State-specific challenges that also render the proposed rule arbitrary and capricious.

1. EPA’s Failure to Justify Its Assumptions Regarding Heat Rate Improvements for Existing Coal-Fired EGUs Is Arbitrary and Capricious

In Building Block 1, EPA focuses its BSER analysis on emission reductions that can be accomplished onsite by coal-fired EGUs through heat rate improvements that reduce the amount of fuel needed to produce a given unit of energy. 79 Fed. Reg. at 34,859. EPA identifies a series of maintenance best practices and equipment upgrades that would improve heat rate and asserts that if they all were implemented, heat rates would improve by four to twelve percent. After making limited adjustments to account for differences between facilities and early implementation of heat rate improvements, EPA proposes that the best system of emission reduction for all coal-fired EGUs is a uniform six percent heat rate improvement. Because EPA failed to adequately justify this approach in the administrative record and ignores current, real-world conditions faced by coal-fired EGUs, this BSER analysis is arbitrary and capricious.

First, even if EPA could demonstrate an adequate record that the best practices and equipment upgrades it identifies can improve heat rate capacity by six percent, EPA’s proposal is arbitrary and capricious because the record fails to establish the extent to which the identified heat rate improvements have yet to be implemented at existing coal-fired EGUs. As Sargent & Lundy explained in their comments on the proposed rule, application of a performance standard to individual coal-fired EGUs would require a “detailed site-specific analysis” that considers, among other factors, “plant design, previous equipment upgrades, and existing operation and maintenance practices.”⁷³ By failing to conduct such a site-specific analysis, EPA failed to justify its assumption that all of those opportunities are currently available to existing facilities. Contrary to EPA’s assumptions that opportunities for significant heat rate improvements are currently available to existing facilities, adoption of these types of heat rate improvements are commonplace among coal-fired EGUs. This is particularly true for more recently constructed facilities, where many of the upgrades identified by EPA were already included in the initial design phase. But even for older facilities, equipment upgrades and maintenance best practices have been widely adopted, especially in States with competitive electricity markets. As EPA has

⁷³ Sargent & Lundy LLC, Comments on the Carbon Pollution Emissions Guidelines for Existing Stationary Sources: Electric Utility Generating Units (EGUs); Proposed Rule at 3-4 (Nov. 24, 2014) (“Sargent & Lundy Comments”).

observed, 79 Fed. Reg. at 34,857, improving heat rates produces more electricity per unit of fuel and, as a result, makes the facilities more competitive from a cost perspective. Thus, many existing coal-fired EGUs have established maintenance best practices and have completed feasible equipment upgrades and cannot reasonably be expected to reduce heat rates further. *See* Sargent & Lundy Comments at 6 (“Minimum heat rate improvements listed in the report would not be realized on units that have already implemented the [heat rate improvement] methods” indentified in Sargent & Lundy’s 2009 Report).

In this regard, EPA’s implicit assumption that coal-fired power plant operators have failed to make cost-effective heat rate improvements defies reality. Power plant operators have strong incentives to make efficient and cost-effective heat rate improvements. The notion that coal-fired power plant operators throughout the United States have uniformly failed to make readily achievable improvements that would improve profitability is inherently implausible. And to the extent EPA would require coal-fired EGUs to make inefficient heat rate improvements that are not economically justified, that only proves the agency has failed to “tak[e] account of the cost of achieving [emission] reduction.” 42 U.S.C. § 7411(a)(1). In light of these strong incentives for coal-fired EGUs to adopt all feasible heat rate improvements, it is arbitrary and capricious for EPA to simply assume based on generalized and hypothetical studies that additional heat rate improvements are available. Instead, as NERC concluded in its reliability evaluation, “[s]ite-specific engineering analyses would be required to determine any remaining opportunities for economic heat rate improvement measures.” NERC Reliability Assessment at 2.

Second, EPA’s proposal is also arbitrary and capricious because it fails to explore how the declining performance of heat rate improvements over time will affect overall emissions from coal-fired EGUs. *See* Sargent & Lundy Comments at 8 (“By omitting normal degradation from its evaluation of fleet-wide average heat rate improvement opportunities, EPA overestimated efficiency improvements that can be achieved and sustained.”). Neither maintenance best practices nor equipment upgrades provide long-term emission reductions at a consistent level after they are implemented. Instead, they are part of an ongoing process where maintenance must occur on a regular basis and certain equipment must be replaced or upgraded several times over the life of a plant. Thus, for any given heat rate improvement, there is a decay function through which the emission reductions gradually decline over time. As a result, even if an existing facility were to implement the heat rate improvements necessary to reduce emissions by six percent, it would not be able to maintain those reductions over time. A more likely scenario would be that different heat rate improvement projects are undertaken at different times and with different decay rates, meaning that facilities can maintain a moderately stable level of heat rate improvement, albeit at a lower rate than what EPA projects is possible under the best circumstances.

Third, EPA fails to consider how compliance with other environmental regulations will affect the ability of coal-fired EGUs to achieve the proposed efficiency improvements. Add-on emission control technology comes at a cost for power plants, because the emissions controls also require energy to operate. This “parasitic load” reduces the efficiency of the power plant because a portion of the electricity that would have been supplied to the grid must be used on-site for pollution control. Given EPA’s reliance on a 2012 baseline as a starting point for emission reductions, more recent emission control projects are not accounted for. For example,

to comply with EPA's Regional Haze Rule, the Big Stone plant in North Dakota is installing a \$400 million air quality control system that will have a parasitic load of 8 MW.⁷⁴ Compliance with EPA's MATS rule will have a similar effect on coal-fired EGUs. Thus, even if EPA were correct that, in theory, coal-fired EGUs could improve heat rate by six percent, the proposed rule would be arbitrary and capricious because EPA fails to consider how the parasitic load from other EPA-mandated pollution control measures will affect the efficiency of existing sources. At a minimum, EPA must adjust the State emission reduction targets to account for the affect that other CAA programs such as MATS, regional haze rules, and CSAPR will have on plant efficiency.⁷⁵

Fourth, EPA's proposal is arbitrary and capricious because the rulemaking record fails to consider the effect of reduced generating capacity on the emissions rate of coal-fired EGUs. *See, e.g.,* NERC Reliability Assessment at 8 ("EPA did not evaluate the effects of lower-capacity factors resulting from dispatching natural gas generation before coal generation."). Performance at coal-fired EGUs is optimized when facilities are operated continuously at full capacity to provide baseload power. Thus, when facilities are operated at less than full capacity, as they would be required to do under the Rule,⁷⁶ they are less efficient and produce more emissions per unit of electricity. *See* Sargent & Lundy Comments at 8 ("EPA's second, third, and fourth building blocks will likely result in coal-fired units cycling more frequently and running more frequently at lower loads.... EPA did not account for decreased dispatch or load profile changes in its heat rate improvement evaluation or economic analysis."). Further, emissions per unit energy are highest during periods of shutdown and startup, meaning that more frequent cycling associated with shifting coal-fired EGUs from base load to intermediate load generation will also increase emissions. Thus, many, if not all, of the emission reductions that could be achieved through heat rate improvements may be offset by the inefficiencies associated with operating coal-fired EGUs less frequently and at lower capacity factors under the changing dispatch priorities identified under Building Block 2.

Fifth, EPA fails to consider the collateral impacts that these heat rate improvements may have on other regulatory programs under the Clean Air Act. Triggering obligations under such programs would impose significant compliance costs that are not addressed in EPA's Regulatory Impact Analysis. In particular, the Associations are concerned that implementing all of the heat rate improvements contemplated by EPA could in turn have the effect of triggering additional

⁷⁴ Written Testimony of Hon. Travis Kavulla, Commissioner, Montana Public Service Commission, House Energy and Commerce Committee, "State Perspectives: Questions Concerning EPA's Clean Power Plan" (Sept. 9, 2014) (Attachment D).

⁷⁵ EPA must also provide States with flexibility to address the parasitic loads of other regulations—such as a revision to the national ambient air quality standards ("NAAQS") for ozone—that EPA may impose between now and the 2020 interim compliance period.

⁷⁶ EPA projects in its BSER analysis that electricity from coal-fired EGUs will decline by 26%. *See* EPA, Data File: Goal Computation –Appendix 1 and 2, *available at* <http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-technical-documents>.

permitting requirements under the New Source Review (“NSR”) program. In fact, EPA has argued in the past that certain heat rate improvements constitute major modifications under the NSR program. If those requirements were triggered, a facility may be obligated to install pollution control equipment for a wide range of pollutants other than GHGs. Using GHG regulations issued under the NSPS program as a means of regulating unrelated pollutants under the more stringent NSR program would constitute unlawful overreach by the Agency. Thus, at a minimum, EPA must exclude from its BSER analysis any heat rate improvements that may trigger NSR when evaluating the emission reductions that can be achieved by coal-fired EGUs, regardless of whether EPA proceeds with a Building Block approach or, more appropriately, limits its BSER analysis to emission reductions inside the fence line. Further, EPA should clarify in the final rule that it will not approve a State implementation plan that would require a coal-fired EGU to trigger NSR permitting obligations.

2. EPA’s Failure to Justify Its Assumptions Regarding Increased NGCC Capacity Is Arbitrary and Capricious

In Building Block 2, EPA projects that coal-fired electricity generation can be reduced significantly by prioritizing the dispatch of NGCC facilities ahead of coal-fired EGUs. The Associations recognize the critical role that natural gas fired EGUs—and in particular NGCC turbines—have and will continue to play in ensuring the reliable supply of low-cost electricity throughout the United States. Further, as a technical matter, the Associations do not dispute that many NGCC facilities are capable of operating at an average capacity factor of 70% or more. That is not controversial. Nevertheless, that is not the assumption EPA relies upon. Instead, it is arbitrary and capricious for EPA to rely on the fact that, in the abstract and on the whole, all NGCC facilities in a given State are necessarily capable of simultaneously operating at a 70% capacity factor by 2020, when EPA assumes that Building Block 2 will be implemented. Every electricity generating technology has its challenges. However, EPA did not fully account for several current challenges associated with existing NGCC units in its BSER analysis. While many of these challenges may be temporary—and it is only a function of time until infrastructure and supply constraints, where they exist, can be overcome—EPA must evaluate existing NGCC facilities within the context of the existing infrastructure in the States in which they are operated. When viewed in that context, there are a number of practical, real-world challenges that must be considered when determining whether existing and under construction NGCC facilities collectively can be dispatched at a 70% capacity factor in a given State. EPA’s proposal is arbitrary and capricious because it fails to adequately evaluate the potential impact of those additional real-world factors on States’ ability to achieve EPA’s Building Block 2 projections in the time frame contemplated by the Agency. Nevertheless, the Associations are confident that NGCC units will continue to play a critical role in the United States’ power generation mix and will continue to play a role in the future in reducing CO₂ emissions.

First, even if EPA is correct that, as a technical matter, all existing NGCC facilities are capable of operating at 70% capacity, EPA failed to consider whether they were legally authorized to do so. Existing NGCC facilities operate pursuant to State-issued permits, and in some cases, those permits may limit a facility’s hours of operation or total amount of fuel that can be used. For example, a facility may rely on a permit condition to limit operating hours or annual fuel-firing rates to maintain its status as a minor source with respect to the Clean Air Act’s PSD permitting program. Such a facility would effectively be barred from operating at the

capacity envisioned by EPA. Likewise, in some cases, specific components at a facility may not be warranted to operate at a 70% capacity, and facilities would incur significant economic risk by operating outside the bounds of those warranties. It is arbitrary and capricious for EPA to ignore these legal constraints in its BSER analysis. At a minimum, EPA must provide a mechanism for States to adjust their emission reduction targets to account for any existing NGCC facilities that are not legally authorized to operate at 70% capacity.

Second, by relying on the nameplate capacity of NGCC facilities on an annual basis, EPA's analysis may mask seasonal variations that limit the amount of coal-fired electricity generating capacity that can be redispatched to NGCC facilities.⁷⁷ Because electricity demand is not consistent, EPA must account for cyclical demand when evaluating the amount of coal-fired electricity generation that can be displaced. For example, in high-demand summer months, NGCC facilities may already operate at or near 70% capacity and, thus, may have little ability to further increase capacity in order to displace coal-fired electricity generation. In contrast, in months with lower overall demand, shifting generation to existing NGCC facilities may completely displace coal-fired electricity generation before a 70% capacity factor is achieved. As a result of these seasonal variations, existing and under construction NGCC facilities may not be capable of displacing as much coal-fired electricity generation as EPA projects, even if NGCCs operate at 70% capacity. Rather than relying on annual generation data, EPA must incorporate seasonal variation to more accurately estimate the effect of increasing capacity at NGCC facilities.

Third, EPA's proposal assumes that electricity produced by different EGUs is completely fungible and that existing and under construction NGCC facilities can immediately substitute for existing coal-fired EGUs. EPA's assumptions ignore the non-generating services that some coal-fired EGUs provide to the electricity generation and transmission sectors. For example, coal-fired EGUs may be located strategically to provide voltage support and other grid reliability benefits. Existing and under construction NGCC facilities at other locations may not be capable of replacing these functions. Likewise, certain coal-fired EGUs may be designated as "black start" facilities that are capable of restarting without any electricity input or for other reasons may be designated as "must run" facilities by FERC or RTOs. These coal-fired EGUs cannot be retired and replaced immediately by existing or under construction NGCCs. While new NGCC facilities could be constructed to provide those services, such new facilities are outside the scope of this rulemaking and EPA's BSER analysis. EPA's BSER analysis must address these other services currently provided by coal-fired EGUs and ensure that they can be provided by other EGUs on a time period that is consistent with EPA's compliance schedule.

Fourth, EPA fails to give adequate consideration to infrastructure changes that may be needed to accommodate the increase in NGCC capacity envisioned in Building Block 2. Unlike coal-fired EGUs, NGCC facilities do not maintain onsite storage of feedstocks and instead rely on real-time delivery of natural gas through pipelines. In some cases, increased natural gas-fired electricity generation may strain or go beyond the capacity of existing pipeline systems and ultimately require additional infrastructure investments. Likewise, because existing NGCC

⁷⁷ As discussed in Section IX.A., *infra*, EPA lacks authority to mandate redispatching of electricity generation.

facilities are not co-located with the coal-fired EGUs whose generation they would displace, additional investments in transmission infrastructure may be needed to ensure that the electricity generated by existing and under construction NGCC facilities can reach consumers currently supplied by coal-fired EGUs. The same challenges related to transmission infrastructure apply to increased renewable energy generation under Building Block 3. In fact, renewable energy generation may pose even more challenges, as locations with renewable energy generation potential may be far removed from population centers that demand electricity. EPA glosses over these challenges by suggesting that any necessary infrastructure can be constructed to accommodate increased NGCC and renewable capacity. It may prove challenging to finance, plan, and complete infrastructure projects by 2020, when Building Block 2 will be implemented under the interim compliance schedule proposed by EPA. The challenges presented by EPA's compliance schedule will be exacerbated by complex and, at times, inefficient federal permitting systems and the opposition efforts that are often mounted against these large-scale infrastructure projects. It is arbitrary and capricious for EPA to fail to consider the degree to which new infrastructure investments will be needed to displace coal-fired electricity generating capacity and the time that such projects will take.

Fifth, EPA simply assumes in its calculation of State emission reduction targets, without support, that all NGCC facilities that are currently under construction will actually be completed and operated. While the Associations have no reason to question the viability of any particular NGCC project, history has shown there is always a risk that unforeseen circumstances could cause an NGCC project to be stalled, delayed, postponed, or canceled.⁷⁸ Nor does EPA provide a contingency plan to adjust a State's emission reduction targets in the event that construction of a facility is postponed or cancelled.

Finally, in the NODA EPA requests comment on "whether to establish a minimum value as a floor for the amount of generation shift for purposes of building block 2" which could be achieved, in part, through co-firing natural gas at existing co-fired EGUs. 79 Fed. Reg. at 64,550. As an initial matter, EPA explicitly rejected co-firing natural gas as BSER in the proposed rule, 79 Fed. Reg. 34,875, and provides no facts in the NODA or elsewhere in the record that would provide a reasoned basis for the Agency to reverse course in a final rule. Further, EPA fails to offer any analysis of a number of potential challenges to co-firing natural gas, including that (1) natural gas igniters installed at coal-fired EGUs should not be run continuously because they are intended to operate during startup, shutdown, and periods of flame instability, (2) safety equipment such as flame scanners pose distinct safety challenges when gas igniters are used, (3) that continuous or long-term co-firing of natural gas can cause problems with ash accumulation, and (4) at lower loads, co-firing natural gas can increase emissions of NO_x and CO and reduce efficiency by forcing other units offline at the facility. EPA must more fully explore these potential challenges before relying on co-firing to reduce CO₂ emissions. Further, while these challenges may be capable of being addressed through equipment upgrades and retrofits, EPA must consider both the cost of those upgrades and whether they would trigger a modification under Section 111(b). EPA asserts in the proposed rule that the costs of fuel-switching from coal to natural gas would be between \$83 and \$150 per metric ton of CO₂ depending on the

⁷⁸ As discussed in Section VII.E.3, *infra*, this is equally true of under construction nuclear facilities.

proportion of natural gas generation after modification. 79 Fed. Reg. at 34,875. EPA concluded in the proposed rule that those costs were too high to qualify as BSER and, without a significant change in EPA's cost analysis, it would be arbitrary and capricious for EPA to rely on co-firing to establish emission reduction targets.

3. EPA's Failure to Justify Its Assumptions Regarding Construction and Retirement of Nuclear Energy Facilities Is Arbitrary and Capricious

As part of Building Block 3, EPA accounts for zero-emission nuclear energy by assuming that no existing "at risk" nuclear capacity will be retired and that all new nuclear energy units under construction will be built. Specifically, with respect to existing nuclear facilities, EPA assumed that six percent of current nuclear capacity is at risk of retirement and applies a uniform credit of six percent of each State's current nuclear capacity to electricity generation when computing each State's emission reduction target. This simplistic approach to avoided retirements is arbitrary and capricious because it fails to account for key differences between States and between individual facilities.

First, EPA's approach assumes that all existing nuclear facilities can continue to operate in perpetuity and fails to include any safety valve to account for facilities that reach the end of their licensed lives. Nuclear facilities must be permitted by the Nuclear Regulatory Commission ("NRC"), and a significant portion of the existing nuclear fleet has already obtained 20-year extensions that are set to expire before, or shortly after, the final 2030 compliance deadline. In fact, 36,000 MW of nuclear generating capacity will reach the end of the 20-year extension period between 2029 and 2035.⁷⁹ EPA fails to consider the possibility that for economic, reliability, or other operational reasons, the facility owners or the NRC determines that the facility has reached the end of its useful life and on that basis declines to seek or grant another extension. Such a decision would be beyond the authority of EPA or the States to control, and EPA must consider whether changes to its emission reduction targets would be required under such circumstances. Further, EPA fails to account for the potential that other, unforeseen events could require a facility to retire. For example, in 2013 the Crystal River 3 facility was retired as a result of unrepairable cracks in the containment building's outer concrete wall.⁸⁰ Likewise, the San Onofre Nuclear Generating Station retired two units as a result of leaks in steam generators.⁸¹ If EPA is to include avoided nuclear retirement in its BSER analysis, it must account for the possibility that similar equipment failures may occur in the future. Moreover,

⁷⁹ NEI, *Subsequent License Renewal: Creating the Foundation for Nuclear Plant Operation Beyond 60 years* (Feb. 2013), <http://www.nei.org/CorporateSite/media/filefolder/NEI-White-Paper-Subsequent-License-Renewal.pdf?ext=.pdf>.

⁸⁰ Press Release, Duke Energy, Crystal River Nuclear Plant to be retired; company evaluating sites for potential new gas-fueled generation (Feb. 5, 2013), *available at* <http://www.duke-energy.com/news/releases/2013020501.asp>.

⁸¹ Press Release, Southern California Edison, Southern California Edison Announces Plans to Retire San Onofre Nuclear Generating Station (June 7, 2013), *available at* <http://www.songscommunity.com/news2013/news060713.asp>.

EPA fails to address what would happen if retirements in a State exceed six percent of the State's nuclear capacity.

Second, EPA's proposed 90% capacity factor for nuclear facilities, while perhaps reasonable for the entire U.S. nuclear fleet, is unrealistic on a smaller, State-level scale. While nuclear facilities can provide reliable baseload energy, both planned and unplanned outages do occur and maintenance, repair, and upgrades can take a significant amount of time to complete. As a result, a single long-term outage could threaten a State's ability to achieve 90% capacity in a given compliance year. Further EPA's uniform application of a six percent "at risk" capacity factor to all States across the board ignores the binary nature of plant retirements. While a uniform figure may be justifiable at a national level, many States have a small number of nuclear facilities and the retirement of even one unit would exceed six percent of the State's existing nuclear capacity. For example, Michigan has four operating nuclear power reactors, the smallest of which represents 20% of the State's nuclear generating capacity. Under the circumstances, an "at risk" capacity factor of less than 20% would be arbitrary and capricious because it assumes that only part of a facility is at risk of retirement. Thus, at a minimum, EPA must conduct a State-by-State analysis and adjust the "at risk" capacity in the event that the State's smallest nuclear energy unit represents more than six percent of the State's total nuclear capacity.

Third, by applying a uniform six percent "at risk" factor to all States, EPA implicitly assumes that all nuclear facilities are equally at risk of retirement. This assumption is unreasonable. Factors such as facility age, permitting cycle, and location in a competitive market or vertically integrated State can all play a role in determining the likelihood of a specific plant's retirement. Given the relatively small universe of existing nuclear energy facilities and the significant impact of this rulemaking, it is arbitrary and capricious for EPA to rely on aggregate national data to set State-specific emission reduction targets. At a minimum, EPA must apply a more granular methodology that evaluates each State independently to determine the amount of existing nuclear capacity that is truly at risk of retirement and then set State-specific "at risk" capacity factors.

Fourth, even apart from EPA's six percent "at risk" factor, EPA independently assumes that, for purposes of determining a State's emission reduction target, that all under construction nuclear plants will be completed. 79 Fed. Reg. at 34,870.⁸² Given the cancellations, delays, and budget overruns experienced by numerous nuclear plants, this assumption is unwarranted.⁸³ As EPA concedes, if a project is abandoned, that would have a "significant impact on the state's ability to meet" the emission reduction target mandated for it by EPA. 79 Fed. Reg. at 34,870.

⁸² EPA is also effectively assuming that the NRC will license these plants. The NRC has refused to issue an operating license in the past, which led to the project being abandoned. <http://www.nrc.gov/reading-rm/doc-collections/nuregs/brochures/br0468/br0468.pdf>.

⁸³ <http://www.timesfreepress.com/news/2012/jun/04/delays-mire-nuclear-plant-construction/>; see also http://en.wikipedia.org/wiki/List_of_canceled_nuclear_plants_in_the_United_States (these projects have all "announced delays and budget overruns").

Further, by making this assumption, EPA is arbitrarily penalizing “first-mover” States.⁸⁴ A State that constructs a nuclear power plant the day after the proposed rule is finalized would be able to use that increased generating capacity to meet its emission reduction target. But Georgia, South Carolina, and Tennessee get no such benefit even though they sought to construct nuclear facilities before EPA published the proposed rule to curb carbon emissions. To the contrary, EPA has set emission reduction targets that will be required in addition to the reductions that would be achieved if the plants under construction were finished and became operational.

4. EPA’s Failure to Justify Its Assumptions Regarding Increased Renewable Energy Generation Is Arbitrary and Capricious

In Building Block 3, EPA also includes expanded “zero-emission” renewable energy generation. To do so, EPA applies a regional approach which averages existing State RPS targets in a given region and then applies that average target to each State in that region, based on the assumption that renewable energy opportunities are uniform within a region. EPA also applies a growth factor that is based on the State’s current renewable energy generation to ramp up renewable energy generation until the target generation level is achieved. Central to EPA’s analysis is the assumption that State RPS targets are an accurate reflection of the renewable energy potential for the State and, by extension, for each State in the region. EPA fails to adequately consider a number of factors that call this assumption into question.

First, EPA’s broad-based regional approach fails to account for differences in renewable energy potential among States. The mere fact that two States are in relative geographic proximity does not mean that they have the same potential to produce renewable energy. Some forms of renewable energy, such as wind, vary dramatically by location even within a State. Thus, the potential for wind energy in a given State says very little about the potential for wind energy in other States in the same general part of the country. For example, West Virginia has been grouped with coastal States such as Maryland and Virginia with the potential to generate substantial amounts of electricity through off-shore wind power. The fact that Maryland and Virginia can generate substantial off-shore wind power provides no basis for concluding that a land-locked State like West Virginia can achieve comparable levels of wind-generated power.

For other renewable energy sources, such as biomass, opportunities vary significantly between States that EPA has placed in the same region. For example, Minnesota, a heavily forested State with significant potential to produce energy from woody biomass, is placed in the same region with North Dakota, a State with few forest resources. It is arbitrary and capricious to establish aggregate regional renewable energy targets without addressing key differences in renewable energy potential among the States in each region.

The problems with EPA’s regional approach are exacerbated by the small number of State RPS goals that EPA uses to establish some regional targets. In some cases, EPA relies on a

⁸⁴ Notably, in *EPA v. EME Homer City Generation, L.P.*, the EPA took the position that its construction of the Clean Air Act should be given deference, *inter alia*, because it accounted for the extent to which States had previously invested in emission reductions. *See* Br. of Resp. EPA, at 49 (S. Ct. Nos. 12-1182, 12-1183).

single State's RPS goal to set a regional renewable energy target. For example, Kansas is the only State on which EPA relies in setting a renewables target of 20% in the 6-State South Central region. *See* EPA, GHG Abatement Measures TSD at 4-11, 12, 15, 17. Likewise, North Carolina is the only State on which EPA relies in setting a renewables target of 10% for the 8-State Southeast region. *Id.*⁸⁵ While the reasoned judgment of a majority of States in a given region may have some relevance in projecting a region's renewable energy potential, it is arbitrary and capricious to ignore the views of the majority of the States in favor of a single State. Under any statistical assessment, a single data point is too small a sample size on which to make such a significant decision.

Further, in order to justify the imposition of regional renewable energy targets, EPA must rely on something more than mere physical proximity. While, in some circumstances, two neighboring States may share some common potential for renewable energy generation, those similarities largely disappear at the level of aggregation proposed by EPA. EPA's brief two-page summary of its regional approach in a technical support document is far from sufficient to demonstrate the reasonableness of this regional approach. *See* EPA, GHG Abatement Measures TSD at 4-12 -13. Moreover, EPA offers no reason to suggest that the NERC and RTO regions that EPA relies on to group States into regions for assigning Building Block 3 goals have any relevance for assessing renewable energy potential. *Id.* EPA must demonstrate that any regional division it selects for Building Block 3 has a nexus to renewable energy potential. It is arbitrary and capricious for EPA to propose a regional grouping for State renewable energy potential based on the current rulemaking record.

Second, EPA's assumption that a State's RPS target accurately reflects renewable energy potential within that State is misguided. State RPS targets may be aspirational and not necessarily supported by an analysis of renewable energy potential within the State. For instance, States sometimes incorporate safeguards into RPS targets in the event that they cannot be achieved. In some cases, States may include safety valves that suspend or scale back the RPS programs if cost thresholds are exceeded. In other cases, States create incentives for certain types of renewable energy by offering additional credits for preferred energy sources, meaning that the credits produced for compliance with the RPS will exceed the actual level of generation. Finally, States may exclude certain classes of power generators, such as municipally-owned power plants or cooperatives, from the RPS obligations, meaning that the States' actual percentage of renewable energy generation on a State-wide level will be less than the amount required by the RPS target.⁸⁶ It is arbitrary and capricious for EPA to ignore these issues when relying on State RPS targets under Building Block 3.

Third, EPA's renewable targets fail to fully consider the intermittent nature of many renewable energy sources, such as wind and solar. In some cases, challenges associated with

⁸⁵ *See also* Florida Public Service Commission, Memorandum re: Briefing on the U.S. Environmental Protection Agency's Proposal to Limit Carbon Emissions from Existing Electric Utility Generating Units at 8 (Aug. 26, 2014).

⁸⁶ Kavulla Testimony at 11 (noting that Montana RPS does not apply to consumer-owned utilities, public power projects, or generators owned by out-of-State utilities).

such intermittent generation could make EPA's renewable energy targets infeasible. In Texas, for example, wind energy is both intermittent and inversely related to demand. For example, wind speeds are typically highest in the early morning, when demand for electricity is at its lowest. Likewise, wind generating capacity in some States, such as Texas, is greatest during the fall and spring months.⁸⁷ In fact, if Texas were to meet EPA's proposed 20% renewable energy goal, renewable energy could, in some circumstances, exceed demand.⁸⁸ Such an occurrence could have significant repercussions that have not been evaluated by EPA. For example, a Texas Public Utility Commissioner has testified that during periods of high renewable generation, Texas could not simultaneously dispatch both nuclear and renewable facilities as EPA assumes in its BSER analysis.⁸⁹ Further, given the long cycling time for nuclear EGUs, they cannot be utilized as reserve capacity to respond to short-term variations in renewable generation.⁹⁰ The potential of having to choose between nuclear and renewable generation will jeopardize the ability of Texas and other States to achieve the emission reduction targets set by EPA. Rather than simply assuming that its BSER analysis can be achieved based on annual generation data, EPA must carefully consider the shorter term, seasonal changes in energy demand and usage that could prevent a State from consistently meeting the electricity generation assumptions used by EPA. This failure to conduct sufficient seasonal modeling also renders EPA's BSER analysis arbitrary and capricious.

Fourth, EPA's reliance on State RPS targets fails to address the fact that many State RPS programs allow out-of-State renewable energy generation to satisfy the State's RPS goal. For example, a Minnesota utility may be able to satisfy its RPS obligation through construction of a wind farm in North Dakota. To the extent that a State permits such out-of-State compliance, its RPS standard may not be a good indicator of the State's assessment of renewable energy potential within the State. Further complicating matters is the fact that neighboring States with the potential to export renewable energy under RPS programs may elect to enact more modest RPS programs, or forego them entirely, because it is more profitable for their utilities to sell renewable energy credits to other States. Thus, in regions where such interstate transfers are common, it would be arbitrary and capricious to assume that all States can achieve the RPS targets of the most aggressive States.

Fifth, it is arbitrary and capricious for EPA to focus on renewable energy *consumption* represented by State RPS goals to define State obligations for renewable energy *generation*. Under EPA's approach, for example, smaller States with little electricity generation can dramatically skew regional renewable energy targets by mandating the consumption of a large percentage of renewable energy imported from neighboring States. For example, Washington

⁸⁷ Written Testimony of Kenneth W. Anderson Jr., Texas Public Utility Commissioner, House Energy and Commerce Committee, "State Perspectives: Questions Concerning EPA's Clean Power Plan" 7 (Sept. 9, 2014) (Attachment E).

⁸⁸ *Id.*

⁸⁹ *Id.*

⁹⁰ *Id.* at 7-9.

D.C. has no commercial energy generating capacity, but nevertheless has set an effective RPS target of 20%. EPA, GHG Abatement Measures Technical Support Measures at 4-11. Including this RPS target on an equal footing with others in the East Central region produces a significant increase in the region's renewable energy generation target, despite the fact that it is not backed up by any renewable energy potential at all. It is arbitrary and capricious for EPA to treat each State equally when setting renewable energy generation targets, without taking into account the specific circumstances impacting each State. EPA failed to consider a generation-weighted approach that gives greater weight to State RPS targets selected by the States that will bear the brunt of any renewable energy mandate adopted by EPA.

Sixth, EPA's growth projections for renewable energy fail to fully account for the cost and implementation challenges faced by large-scale renewable energy projects. Particularly for States with large generating capacities, annual growth factors in the double digits may prove difficult to sustain. For example, in Texas—a State with a 20% growth factor—EPA projects that renewable energy capacity can increase by 5 million MWh per year during the interim compliance period. Past examples of large-scale renewable energy programs suggest that this assumption is inadequately justified. For example, in 2008, the Texas PUC assigned nearly \$5 billion to construct the lines needed to transmit approximately 18,000 MW of wind power from west Texas and the Texas Panhandle to population centers. This massive infrastructure project, which took more than six years to complete after authorization from the PUC, demonstrates both the time and resources needed to construct renewable energy capacity and ensure it can be delivered to customers. EPA must more fully consider these implementation challenges and how they may affect its projected growth assumptions.

Seventh, EPA's calculations are inherently arbitrary because they effectively disregard State findings that no significant RPS target could be set. Specifically, while EPA purported to take as determinative States' assessments of their own potential for renewable energy, 79 Fed. Reg. at 34,866, it in fact only took as determinative the findings by States that have adopted a specific RPS target. In contrast, EPA disregarded the conclusions of any State that considered adoption of an RPS standard, but ultimately decided that binding renewable energy targets were not feasible. Including States that adopted a voluntary RPS that is effectively a 0% RPS would dramatically alter the regional renewable energy targets calculated by EPA in its BSER analysis. Thus, for example, even though West Virginia determined that a mandatory RPS standard was not feasible for the State, EPA nonetheless disregarded that finding without any explanation, and instead assumed that West Virginia could achieve a 16% RPS. Incorporating West Virginia's decision not to adopt a mandatory RPS would have reduced the entire region's target from 16% to 14%.

5. EPA's Failure to Justify Its Assumptions Regarding Demand-Side Energy Efficiency Improvements Is Arbitrary and Capricious

In Building Block 4, EPA evaluated energy efficiency studies and energy efficiency programs adopted by States to determine the potential for energy efficiency programs to reduce energy demand and, thereby, reduce the need to operate fossil fuel-fired EGUs. Based on these sources, EPA projected that States could achieve an incremental energy efficiency savings of 1.5% of retail sales, with a yearly rate of improvement of 0.2% until a State reached the 1.5% target. The Associations agree with EPA that demand-side energy efficiency opportunities offer

potential economic benefits to consumers through reduced electricity bills, as well as environmental benefits due to reduced carbon emissions. Nevertheless, the Associations have remaining concerns regarding EPA's analysis, which applies these assumptions uniformly across all the States.

In particular, the Associations are concerned with EPA's reliance on data derived from the recent recession and slow economic recovery period that followed. While the energy efficiency gains observed during this period are promising, those periods do not reflect representative economic conditions. In particular, they are not representative of higher demand scenarios associated with periods of more rapid economic growth. In order to demonstrate the reasonableness of EPA's assumptions for energy efficiency, EPA must expand its analysis and provide assurance that the incremental savings target can be achieved under a more robust set of economic conditions. Further, EPA did not attempt to account for the extent to which States have already adopted energy efficiency programs. A State that has a mature and established program cannot be expected to achieve the same levels of demand reduction as a State that has only just begun its program and is able to target the most easily implemented, lowest-cost reduction programs.

6. EPA's Alternative Approach to Building Blocks 3 And 4 In The October 30th NODA Is Arbitrary and Capricious

In the October 30th NODA, EPA suggests alternative methods for computing State emission reduction targets that would increase their stringency. Specifically, EPA suggests that it could further reduce the State's projected reliance on coal-fired EGUs by assuming that the increased renewable energy generation and demand side energy efficiency improvement in Building Blocks 3 and 4 would displace existing coal-fired generation on a one-to-one basis. 79 Fed. Reg. at 64,552-53. Further reducing coal-fired electricity generation in such a manner would make the emission reduction targets even less achievable and would exacerbate the grid reliability challenges identified above. Further, such an approach fails to account for important differences between the Building Blocks. EPA provides no basis to support an argument that electricity could be shifted away from existing coal-fired EGUs by adding renewable energy capacity or reducing demand pursuant to Building Blocks 3 and 4. First, EPA includes each State's existing renewable energy capacity in Building Block 3. Those facilities are already producing electricity alongside coal-fired EGUs and, as a result, cannot be called upon to displace coal-fired electricity generation. Second, by incorporating new renewable energy generation and energy efficiency measures into its BSER analysis, EPA necessarily accounts for new electricity demand that will occur over the same time period. EPA cannot simply assign all new electricity generating capacity (and efficiency-induced demand reductions) toward the displacement of coal-fired electricity generation without considering how States will meet new demand. This is particularly true for States that already have RPS and EERS programs in place and are relying on them to meet at least a portion of the growth in electricity demand.

7. EPA's Nationwide BSER Analysis Is Arbitrary and Capricious Because it Fails to Account for State-Specific Conditions

In the proposed rule, EPA conducts its BSER analysis on what is essentially a uniform national level, using State electricity generation data from 2012 as a starting point. Thus, aside

from plugging State-specific generation data into a national uniform model, EPA fails to address a single State specific condition that may warrant additional scrutiny and, in some cases, a departure from EPA's generally applicable BSER analysis. Unless EPA addresses the practical reality that the nation's energy infrastructure is highly dependent upon State specific issues in virtually every instance, EPA's BSER analysis will be arbitrary and capricious.

First, for example, EPA's treatment of different types of zero-emission sources in conducting its BSER analysis results in arbitrary and disproportionate treatment of States. For renewable energy sources other than hydroelectric power, EPA includes all electricity generation, including future generation from new sources. For nuclear energy, EPA includes all electricity generation from sources under construction and six percent of electricity generation from existing sources. For hydroelectric power, EPA excludes all existing electricity generation. For States such as Arizona, with significant amounts of nuclear and hydroelectric generation,⁹¹ this has a significant effect on the emission reduction target that EPA proposed for the State through its BSER analysis.

Second, by conducting a State-level BSER analysis that assumes a perfectly fungible electricity generation and transmission system, EPA failed to consider the challenges faced by States which are members of multiple RTOs. In such States, for example, dispatching decisions are made by different regulators for different parts of the State and electricity may not be able to move easily between RTOs. Thus, NGCC facilities located in one RTO may not be capable of substituting for a coal-fired EGU located in a different RTO. In the same manner, portions of a State with potential for new renewable energy capacity may not be able to serve growing demand in a different RTO. South Dakota, for example, has two fossil fuel-fired EGUs: the gas-fired Deer Creek Generating Station, which is dispatched through the SPP, and the coal-fired Big Stone plant, which is dispatched through MISO.⁹² Despite the fact that these facilities serve different customer bases and are subject to dispatching by different system operators, EPA assumes that because they are located in the same State, electricity can be shifted seamlessly from Big Stone to Deer Creek. Similar problems may exist in other States, such as Arkansas, where electricity is managed by multiple ISOs or RTOs.⁹³ Thus, for States with multiple ISOs or RTOs, the ability of a State to reduce its emissions using the four Building Blocks may be significantly less than what EPA has projected. It is arbitrary and capricious for EPA to set State emission reduction goals on a system basis without considering how the electricity system in each State is managed.

Third, EPA has failed to account for and credit States that have taken early action with respect to renewable energy and energy efficiency programs. For example, States such as

⁹¹ Hydroelectric and nuclear power make up more than 25% of all electricity generation in Arizona. See EIA, Electricity: Detailed State Data, available at <http://www.eia.gov/electricity/data/state/>.

⁹² Kavulla Testimony at 7-8.

⁹³ Letter from Dustin McDaniel, Attorney General, Arkansas to Avi S. Garbow, General Counsel, EPA (Aug. 4, 2014).

Pennsylvania have already enacted RPS standards and EERS programs and have made strides in implementing those programs. The same concerns arise in the ERCOT grid in Texas. To place those States on equal footing with other States, EPA should give the early actors credit for the emission reductions they achieve in the same manner that EPA proposes to give credit to other States that initiate such programs in the future. Instead, EPA has used those early actions to set a more stringent baseline for early acting States and is demanding more, rather than less, in the form of future emission reductions. In this manner, EPA is treating different States in an arbitrary and capricious manner.

Fourth, EPA is treating different States differently by requiring emission reductions that vary dramatically with respect to the amount of GHGs currently emitted by affected EGUs in the State. For example, Texas is responsible for more than 20% of the total CO₂ reductions required under EPA's BSER analysis, despite the fact that it is only responsible for 11% of the total CO₂ emitted from fossil fuel-fired EGUs nationwide. The reductions required by sources within a State should bear some resemblance to the CO₂ emissions for which that State is responsible. It is arbitrary and capricious for EPA to require some States to shoulder a burden so far out of line with their relative of CO₂ emissions.

VIII. EPA'S PROPOSED PORTFOLIO APPROACH IS UNLAWFUL

EPA's proposal is also unlawful because it would permit States to include in their implementation plans binding legal obligations on entities other than affected fossil fuel-fired EGUs. A central component of the flexibility touted by EPA is the so-called "portfolio approach" that would permit States to comply with the emission reduction targets by "impos[ing] requirements on other affected entities (e.g., renewable energy and demand-side energy efficiency measures) that would reduce CO₂ emissions from the affected EGUs." 79 Fed. Reg. at 34,853. In other words, EPA would authorize States to implement Section 111(d) standards of performance by imposing binding legal obligations on an entity simply because it could either replace fossil fuel-fired electricity generation or reduce its own electricity consumption. The proposed portfolio approach is unlawful because the Clean Air Act does not authorize EPA and the States to expand standards of performance under Section 111(d) beyond the source categories already subject to regulation under Section 111(b). EPA cannot offer States the ability to regulate any generator or consumer of electricity (*i.e.* the entire economy) simply because doing so provides for greater emission reductions than limiting regulations to the affected fossil fuel-fired EGUs.

A. The Plain Language Of Section 111(d) Bars EPA's Portfolio Approach

In enacting Section 111(d), Congress imposed a series of limitations on the authority of EPA and the States to regulate existing sources. Chief among them is that standards of performance may only be established for existing sources "to which a standard of performance would apply if such existing source were a new source." 42 U.S.C. § 7411(d)(1). Thus, EPA must make a significant contribution endangerment determination for a source category and establish standards of performance for new sources before EPA or the States can establish standards of performance for existing sources. EPA and the States cannot short-circuit this process by using Section 111(d) to impose binding legal obligations on sources that are outside

of the affected source category and, more importantly, are not otherwise subject to regulation under Section 111(b).

Further, EPA's assertion that its proposal to authorize a portfolio approach must be afforded deference is incorrect. EPA asserts that "the terms of CAA section 111(d)(1) do not explicitly address whether, in addition to emissions limits on affected EGUs, State plans may include other measures for achieving the emission performance level. Nor do they address whether entities other than affected EGUs may be subject to requirements that contribute to reducing EGU emissions." 79 Fed. Reg. at 34902. The fact that Congress did not specifically address the merits of a "portfolio approach" does not mean that there is a statutory gap for EPA to fill:

To suggest ... that *Chevron* step two is implicated any time a statute does not expressly *negate* the existence of a claimed administrative power (*i.e.*, when the statute is not written in 'thou shalt not' terms), is both flatly unfaithful to the principles of administrative law ... and refuted by precedent. Were courts to *presume* a delegation of power absent an express *withholding* of such power, agencies would enjoy virtually limitless hegemony, a result plainly out of keeping with *Chevron* and quite likely with the Constitution as well.

Ry. Labor Exec. Ass'n v. Nat'l Mediation Bd., 29 F.3d 655, 671 (D.C. Cir. 1994) (emphasis added); *see also Sea-Land Serv. Inc.*, 137 F.3d at 645; *Michigan v. EPA*, 268 F.3d 1075, 1082 (D.C. Cir. 2001); Stephen Breyer, *Judicial Review of Questions of Law and Policy*, 38 Admin. L. Rev. 363, 373 (1986) ("To read *Chevron* as laying down a blanket rule, applicable to all agency interpretations of law, such as 'always defer to the agency when the statute is silent,' would be seriously overbroad, counterproductive, and sometimes senseless.").

Given the broader context of Section 111, the lack of an explicit reference to a "portfolio approach" in Section 111(d) suggests that regulations should be limited to affected sources, not that EPA should expand regulations as it sees fit. *UARG*, 134 S. Ct. at 2442 ("[R]easonable statutory interpretation must account for both 'the specific context in which ... language is used' and the broader context of the statute as a whole." *Robinson v. Shell Oil Co.*, 519 U.S. 337, 341 (1997)."). The central regulatory focus of Section 111 is on source categories, and Congress prescribed a detailed process that EPA and the States must go through to impose regulations on a given source category: EPA must make a significant contribution endangerment determination for the pollutant and source category, EPA must establish standards of performance for new sources, and only then may EPA and the States establish standards of performance for existing sources. 42 U.S.C. § 111(b), (d). When viewed in this broader context, the absence of a specific reference to the regulation of other source categories under Section 111(d) does not suggest a statutory gap. Instead, it is fully consistent with the implicit understanding that Section 111(d) would only be applied to existing sources in a source category for which EPA had made an endangerment determination and established standards of performance for new sources.

Thus, EPA and the States are foreclosed from basing implementation plans on a "portfolio approach" that imposes legal obligations on any entities other than the fossil fuel-fired EGUs in the source categories covered in EPA's January 2014 proposal under Section 111(b) because these are the only source categories for which EPA has taken any action at all to regulate

GHG emissions under Section 111. Unless and until EPA conducts a significant contribution endangerment determination and establishes standards of performance for new sources under Section 111(b), it cannot authorize States to use Section 111(d) to impose binding legal obligations to reduce GHG emissions on nuclear electricity generators, renewable electricity generators, or electricity consumers. Further, it is unlikely that EPA could ever regulate GHG emissions from these sources categories under Section 111 because, as the Agency has recognized, they produce either zero- or near-zero emissions of CO₂ and, therefore cannot contribute significantly to the endangerment of public health or the environment. Thus, under Section 111, neither EPA nor the States have the authority to unilaterally impose emission reduction obligations on any existing sources other than affected fossil fuel-fired EGUs, the only source categories currently subject to regulation under Section 111(b).

B. EPA’s Proposed Emission Reduction Targets Are Arbitrary And Capricious Because States Cannot Achieve Them Solely Through Regulation Of Affected EGUs

In light of the unlawfulness of EPA’s proposed “portfolio approach,” the proposed emission reduction targets are arbitrary and capricious because they cannot be achieved by existing fossil fuel-fired EGUs alone. To obtain EPA approval, a State implementation plan must identify an “emission performance level for each plan performance period” that is “equivalent to or better than the level of rate-based CO₂ emission performance goals” established by EPA. 79 Fed. Reg. at 34,951 (proposed 40 C.F.R. § 60.5740(a)(3)). Further, each emission standard included in the plan must be quantifiable, non-duplicative, permanent, verifiable, and enforceable with respect to an affected entity.” *Id.* at 34,952 (proposed 40 C.F.R. 60.5741(a)(6)).

There are no adequately demonstrated emission reduction technologies available to coal-fired EGUs that can achieve the emission reduction targets proposed by EPA. EPA has appropriately ruled out all emission reduction options other than heat rate improvements at coal-fired EGUs, *id.* at 34,856-57, and, as the Associations have explained, most EGUs cannot achieve even a six percent improvement in heat rate, *see* VII.E.1., *supra*.⁹⁴ Thus, as a practical matter, a State implementation plan would have to either impose mandatory limits on operating hours or mandate facility closures in order to satisfy EPA’s criteria.

However, a State cannot simply mandate that existing coal-fired EGUs curtail operations or close prematurely. States have an obligation to ensure that there is sufficient electricity generating capacity to meet the demand of their citizens. In many States, existing coal-fired electricity generating capacity is needed to meet electricity demand, and States cannot allow—much less mandate—a significant reduction in coal-fired electricity generating capacity without adequate assurances that the lost generating capacity can be seamlessly replaced. Contrary to EPA’s suggestion, States cannot simply assume that other low-carbon sources will step in to fill the void left by forced reduction in coal-fired electricity generating capacity. Thus, to meet their legal obligation to provide reliable electricity to their residents, States must necessarily couple

⁹⁴ Even if a 12% improvement in heat rate—the upper range of EPA’s BSER projections—were possible, coal-fired EGUs would still fall well short of achieving EPA’s proposed emission reduction targets. *See* 79 Fed. Reg. at 34,859.

any mandatory reduction in coal-fired electricity generating capacity with mandatory increases in other forms of generating capacity. In other words, the only way that a State can achieve EPA's proposed emission reduction targets while maintaining grid reliability is to adopt a portfolio approach that imposes legal obligations on other entities. Because such a portfolio approach is unlawful, EPA's proposed emission reduction, as developed under EPA's Building Block structure are, by definition, unsupported and, therefore, arbitrary and capricious.

IX. EPA CANNOT SET A STANDARD FOR STATE IMPLEMENTATION PLANS THAT EPA ITSELF WOULD LACK THE AUTHORITY TO IMPLEMENT IN A FEDERAL IMPLEMENTATION PLAN

The unlawfulness of EPA's proposed beyond-the-fence-line approach to setting emission reduction targets is further underscored by the fact that EPA lacks the legal authority under the CAA to implement Building Blocks 2-4. Under Section 111(d)(2), EPA must develop an implementation plan to achieve the emission reduction targets in the event that a State fails to submit an implementation plan or submits a plan that EPA deems unsatisfactory. 42 U.S.C. § 7411(d)(2). However, as a federal agency, EPA has limited regulatory authority and can only exercise the power that has been delegated to it by Congress. See *North Carolina v. EPA*, 531 F.3d 896, 922 (D.C. Cir. 2008) ("Lest EPA forget, it is 'a creature of statute,' and has 'only those authorities conferred upon it by Congress'; 'if there is no statute conferring authority, a federal agency has none.'" (quoting *Michigan*, 268 F.3d at 1081)).

Thus, it is not enough for EPA to outline a plan showing how CO₂ emissions from the electricity sector might be reduced. EPA must also demonstrate that it has the legal authority to implement the specific emission reduction measures that it identifies. EPA cannot do so here. While the CAA gives EPA authority to impose emission reduction obligations on affected EGUs that are part of the regulated source category, it does not give EPA authority to implement the emission reductions that would be achieved through the other Building Blocks. Specifically, as explained below, EPA lacks authority to make dispatching decisions for a States' EGUs, to mandate the continued operation of nuclear facilities, to impose State-specific RPS programs, or to impose demand-side energy efficiency requirements on electricity consumers. Because, as EPA acknowledges, some combination of these actions are necessary to achieve each States' emission reduction target, it is clear that EPA lacks the legal authority to develop an implementation plan that can achieve the proposed standards of performance. Thus, to comply with its obligations under Section 111, EPA must withdraw the rule and propose alternative emission reduction goals that can be achieved through emission reductions that EPA has the legal authority to implement.

Nor can EPA rely on the more expansive authority retained by States as a means of achieving the proposed emission reduction targets. First, and most fundamentally, there is no guarantee that each State will submit an implementation plan, let alone one that EPA deems satisfactory. Given the complexities in EPA's proposal, there is a significant likelihood that States will not be able to submit satisfactory implementation plans within the proposed time frames. Likewise, given the controversial nature of this rule, it is possible that some States may simply refuse to prepare an implementation plan at all. Under either scenario, EPA has a statutory obligation to establish standards of performance and a federal implementation plan and, therefore, must design emission reduction targets that it is capable of implementing. Second,

EPA cannot use the CAA to require States to adopt implementation plans that include provisions that EPA lacks authority to impose. *See North Carolina*, 531 F.3d at 922 (EPA cannot require States to have SIP provisions mandating the retirement of Title IV trading allowances when EPA lacks the authority to terminate or limit such allowances). Thus, even if the States do have the authority to implement Building Blocks 2-4, EPA cannot use the NSPS program to commandeer the States' authority by requiring them to do so.

A. EPA Cannot Implement Block 2 Because It Does Not Have Authority To Make Electricity Dispatching Decisions

EPA cannot include Building Block 2 in a federal implementation plan because it does not have the authority to make electricity dispatching decisions. As the Associations explained in Section VI.B., *supra*, the authority to regulate the dispatch of electricity is reserved to the States in the FPA. The FPA explicitly reserves to the States jurisdiction “over facilities used for the generation of electric energy or over facilities used in local distribution or only for the transmission of electric energy in intrastate commerce.” 16 U.S.C. § 824(b)(1). In doing so, Congress recognized the States’ “traditional responsibility in the field of regulating electrical utilities for determining questions of need, reliability, cost and other related state concerns.” *Pac. Gas & Elec.*, 461 U.S. at 205.

At the most fundamental level, States have the authority to determine whether to operate a vertically integrated or competitive market system and to establish parameters under which those systems operate. Furthermore, in many cases, the States have partnered with ISOs or RTOs to manage aspects of electricity dispatching and transmission and to ensure the consistent and reliable delivery of electricity to consumers. Within this context, States retain the authority to determine the rules and priorities for dispatching various electricity generating units, taking into account cost, reliability, and other priorities such as the generation of renewable energy. Thus, EPA cannot rely on increasing utilization at existing NGCC facilities as part of a federal implementation plan when dispatching decisions are made by the State and implemented by the States or ISOs and RTOs.

Furthermore, to the extent that there is any residual federal authority over dispatching decisions at the federal level, it does not belong to EPA. *See, e.g., New York*, 535 U.S. at 19-20 (“[T]he text of the FPA gives FERC jurisdiction over the ‘transmission of electric energy in interstate commerce and ... the sale of electric energy at wholesale in interstate commerce.’” (quoting 16 U.S.C. § 824(b))). For example, to the extent that States participate in RTOs with interstate transmission of electricity, changes to dispatching priorities would be subject to federal oversight through FERC, not EPA. *See* 16 U.S.C. §§ 824d, 824e. Thus, the division of authority between federal and State authorities under the FPA is clear, and leaves no role for EPA to play. In light of this clear statement from Congress in the FPA, there is no basis to suggest that Congress intended to give EPA broad authority to regulate electricity dispatching as a means of controlling pollution under Section 111(d). *See Whitman v. Am. Trucking Ass’n, Inc.*, 531 U.S. 457, 468 (2001) (“Congress ... does not alter the fundamental details of a regulatory scheme in vague terms or ancillary provisions—it does not, one might say, hide elephants in mouseholes.”).

B. The NRC—Not EPA—Has Authority To Make Decisions Regarding Authorization Or Decommissioning of Nuclear Power Facilities

EPA cannot include Building Block 3’s reliance on avoided retirement of nuclear facilities in a federal implementation plan because it does not have the authority over the operation of such facilities. Under the Atomic Energy Act, the NRC is given the authority to issue, renew, and, if necessary, revoke commercial licenses for nuclear energy facilities. 42 U.S.C. § 2133. Further, the savings clause in the Atomic Energy Act states that “this section shall not be deemed to confer upon any Federal, State, or local agency any authority to regulate, control, or restrict any activities of the Commission.” *Id.* § 2018. Thus, EPA lacks the authority to compel a nuclear energy facility to remain in operation and could not overrule a decision by the NRC not to renew an existing facility’s license. Given EPA’s lack of authority over nuclear energy generation, it cannot rely on avoided nuclear generating capacity as part of a legally enforceable federal implementation plan.

C. EPA Lacks The Authority To Impose Or Amend State-Specific Renewable Portfolio Standards Or Other Programs That Mandate The Use Of Renewable Energy

EPA also lacks authority to impose a State-specific RPS program or revise an existing State RPS program as part of a federal implementation plan. First, consistent with the States’ general authority over electricity generation, dispatching, and transmission, RPS standards have come exclusively from the States. The decision to adopt (or not adopt) an RPS is a residual authority reserved by the States and cannot be usurped by EPA. Second, there is nothing in the Clean Air Act to suggest that Congress has delegated to EPA the authority to use an RPS program of any kind—let alone a State-specific RPS—as a means of reducing emissions. Third, Congressional action with respect to the Renewable Fuel Standard (“RFS”) and inaction with respect to several RPS bills further supports the conclusion that the Clean Air Act does not implicitly authorize EPA to impose an RPS on the States. The closest federal program to an RPS is the RFS Program, which requires that minimum quantities of renewable fuel be blended into gasoline and diesel fuel. Significantly, EPA’s authority to implement the RFS was not inherent in the structure of the Clean Air Act itself, but required Congressional action in the Energy Policy Act of 2005 (“EPAAct of 2005”) and the Energy Independence and Security Act of 2007 to set the specific volumes of renewable fuel that must be blended into transportation fuels. *See* 42 U.S.C. § 7545(o). In addition, Congress has repeatedly considered, but failed to pass, bills that would establish similar renewable energy standards for the electricity sector. *See, e.g.*, S. 3813, 111th Cong. (2010); H.R. 890, 111th Cong. (2009); H.R. 2454, 111th Cong. (2009).⁹⁵ Taken together, the passage of two RFS bills and the consideration of and failure to pass multiple RPS bills strongly suggests that Congress has not delegated to EPA (or to any other federal agency) the authority to impose renewable energy standards. Thus, in the absence of Congressional action, EPA lacks authority to implement Building Block 3.

⁹⁵ Consistent with the FPA, these bills would have given the Department of Energy, not EPA, the authority to implement a federal RPS program.

D. EPA Lacks The Authority To Mandate State-Specific Demand-Side Energy Efficiency Programs

Likewise, EPA lacks authority to impose a State-specific demand-side energy efficiency program as part of a federal implementation plan. First, as EPA recognizes in the proposed rule, EERS programs, like RPS programs, are adopted and implemented at the State level and reflect the exercise of authority that was reserved by the States. This is consistent with the general federal approach to energy efficiency, which has focused on voluntary programs, such as tax incentives and grants, rather than mandatory adoption of energy efficiency measures.⁹⁶ In contrast, Congress has only authorized one federal energy efficiency program, which is administered by the Department of Energy, not EPA. *See* 42 U.S.C. § 6291 *et seq.*; 10 C.F.R. pt. 431. Second, there is nothing in the Clean Air Act to suggest that EPA has authority to require States to implement mandatory energy efficiency obligations. Nor has EPA ever asserted that it possessed such authority in the past. In fact, EPA’s website highlights State programs, such as energy efficiency portfolio standards, as means to improve energy efficiency.⁹⁷ In sum, the authority to impose energy efficiency requirements on retail consumers of electricity rests exclusively with the States and, to the extent that there is any federal role at all with respect to mandatory energy efficiency standards, it is exercised by agencies other than EPA.

X. EPA’S PROPOSAL TO REGULATE MODIFIED AND RECONSTRUCTED SOURCES UNDER CAA § 111(d) IS UNLAWFUL

EPA’s proposal here (and in the proposed rule for modified and reconstructed sources) would unlawfully subject modified and reconstructed sources to standards of performance under both Section 111(b) and 111(d). *See, e.g.,* 79 Fed. Reg. at 34,903-04; *see also* 79 Fed. Reg. at 34,963. Under the plain meaning of Section 111, these standards of performance are mutually exclusive and cannot both be applied to the same source: A source cannot simultaneously be “new” and “existing.” Further, EPA’s proposed justifications for continuing to regulate modified and reconstructed sources under Section 111(d) are unreasonable. Even if EPA’s underlying factual assumptions are correct, this merely underscores the legal and practical defects in the proposed rule. To the extent that EPA’s proposed regulations are incompatible with the plain meaning of the Clean Air Act, it is EPA’s proposal that must yield.

The standards of performance established by EPA under Section 111(b) extend beyond newly constructed sources and also include “modified” sources. 42 U.S.C. § 7411(a)(2) (“The term ‘new source’ means any stationary source, the construction *or modification* of which is commenced after the publication of regulations ... prescribing a standard of performance under this section which will be applicable to such source.”) (emphasis added). In its implementing regulations, EPA subsequently expanded the definition of new sources to include reconstructed sources as well. *See* 40 C.F.R. § 60.15. Existing sources are then defined in Section 111 as “any

⁹⁶ *See* DSIRE Database for State Incentives for Renewables and Efficiency, Financial Incentives for Energy Efficiency, available at <http://www.dsireusa.org/summarytables/finee.cfm>.

⁹⁷ EPA, Energy Efficiency, available at <http://www.epa.gov/statelocalclimate/state/topics/energy-efficiency.html>.

stationary source other than a new source.” 42 U.S.C. § 7411(a)(6). In other words, existing sources are defined as the residual sources that are not considered “new” under Section 111. The two categories are mutually exclusive.

By explicitly defining new and existing sources in mutually exclusive terms, the plain language of Section 111 dictates that a source cannot simultaneously be both a new source and an existing source. It follows logically then that the applicability of standards of performance under Section 111(b) for new sources and Section 111(d) for existing sources must also be mutually exclusive. Thus, a single source cannot be simultaneously subject to standards of performance under both Sections 111(b) and (d). Congress’ intent here is further underscored by the language of Section 111(d), which authorizes States to impose standards of performance only on sources “to which a standard of performance would apply *if such existing source were a new source.*” 42 U.S.C. § 7411(d)(1) (emphasis added). The contingent nature of this provision makes clear that States cannot impose standards of performance under Section 111(d) on new sources which are in fact subject to standards of performance under Section 111(b). The fact that Section 111(d) does not expressly state that standards of performance no longer apply after modification or reconstruction, 79 Fed. Reg. at 34,904, is of no moment. “A statutory ‘provision that may seem ambiguous in isolation is often clarified by the remainder of the statutory scheme.’” *UARG*, 134 S. Ct. at 2442 (quoting *United Sav. Ass’n of Tex.*, 484 U.S. at 374). Here the definitions themselves make clear that regulation under Sections 111(b) and 111(d) must be mutually exclusive. The regulatory structure of Section 111 further underscores the mutually exclusive nature of Sections 111(b) and (d). Section 111(b) authorizes EPA to regulate new sources while Section 111(d) directs States to establish standards of performance for existing sources. There is no basis to suggest that Congress would have intended a source to be subject to two different standards of performance adopted by two different regulators.⁹⁸

EPA’s purported justifications for continuing to regulate modified and reconstructed sources under Section 111(d) are unpersuasive and simply underscore the unlawful, arbitrary, and capricious nature of the proposed rule. First, EPA asserts that its approach is necessary “to assure the integrity of the CAA section 111(d) plan” because “[u]ncertainty about whether units would remain in the program could be very disruptive to the operation of the [Section 111(d)] program.” 79 Fed. Reg. 34,904. Even if EPA is correct that the potential for modified and reconstructed sources to be removed from Section 111(d) implementation plans may create uncertainty and pose challenges to implementing the proposed rule, that does not give EPA authority to override the statutory text and regulate modified and reconstructed sources under Section 111(d). As the Supreme Court recently held, “[a]n agency has no power to ‘tailor’ legislation to bureaucratic policy goals by rewriting unambiguous statutory terms.” *UARG*, 134 S. Ct. at 2445.

⁹⁸ EPA cannot solve this apparent contradiction by allowing Section 111(d) implementing authorities to set standards of performance for modified and reconstructed sources. *See, e.g.*, 79 Fed. Reg. at 34,926. (“There is no ... presumption covering sub-delegations to outside parties. Indeed, if anything, the case law strongly suggests that sub-delegations to outside parties are assumed to be improper absent an affirmative showing of congressional authorization.” *United States Telecom. Ass’n v. FCC*, 359 F.3d 554, 565 (D.C. Cir. 2004).

Second, EPA expresses “concern[] that owners or operators of units might have incentives to modify purely because of discrepancies in the stringency of the two programs” 79 Fed. Reg. at 34,904. Again, the fact that EPA concedes that the standards of performance for existing sources will be more stringent than those for modified and reconstructed sources simply underscores the unlawful nature of the proposed rule. The inclusion of modified and reconstructed sources under Section 111(b) reflects the intent of Congress and EPA that such sources may be subject to more stringent standards of performance than existing sources. *See, e.g.*, 40 Fed. Reg. at 58,416, 58,417 (“The reconstruction provision is intended to apply where an existing facility’s components are replaced to such a degree that it is technologically and economically feasible for the reconstructed facility to comply with the applicable standards of performance [under Section 111(b)].”); *see also* 40 Fed. Reg. at 53,540, 53,340 (“[T]he degree of control reflected in EPA’s emission guidelines will take into account the costs of retrofitting existing facilities and thus will probably be less stringent than corresponding standards of performance for new sources.”). This approach is inherently sensible, as facilities undergoing modification or reconstruction may have opportunities to incorporate emission control technology not available to other existing sources. Here, EPA turns that logic on its head and suggests that existing fossil fuel-fired EGUs may be subject to standards of performance so stringent that they go beyond the “best system of emission reduction” that has been “adequately demonstrated” for a modified or reconstructed source in the same source category. The fact that a source could gain relief by undergoing a modification or reconstruction is clear evidence that the proposed regulations for existing sources are unlawfully stringent.

XI. EPA’S INCLUSION OF SIMPLE CYCLE TURBINES IS ARBITRARY, CAPRICIOUS, AND UNLAWFUL

EPA should also exclude simple cycle turbines both from the category of affected EGUs and from EPA’s emission reduction goal calculations⁹⁹ as it proposed to do in the initial April 2012 proposal for newly constructed fossil fuel-fired EGUs. *See* 77 Fed. Reg. 22,392. Treating simple cycle turbines as affected EGUs in the same manner as NGCC facilities is inconsistent with their role in supplying power, will needlessly subject owners and operators of simple cycle turbines to an unprecedented *post hoc* applicability test, and will reduce the flexibility that States will need to cope with the dramatic increases in renewable power generation that will be required to meet EPA’s emission reduction targets. Alternatively, if EPA is determined to regulate CO₂ emissions from existing simple cycle turbines, the Associations request that EPA adjust the emissions guidelines or emission reduction targets to reflect the emissions limits that can be achieved by existing simple cycle turbines, now and under projected future conditions where increased renewable generation may require them to increase capacity.

⁹⁹ While EPA asserts that it has excluded from its goal computations any simple cycle turbines that failed to qualify as an affected EGU, at least some simple cycle turbines do satisfy the applicability criteria and are included in the proposed rule. *See* 79 Fed. Reg. at 34,895 n.260.

A. Simple Cycle Turbines Play A Fundamentally Different Role In Energy Generation Than NGCC Turbines

Simple cycle turbines play a critical and unique role in providing peaking power and assuring grid reliability. Simple cycle turbines can cold start quickly, easily scale through loads, and start and stop several times per day. As EPA recognized in the proposed standards of performance for modified and reconstructed sources, this flexibility allows them to fill the unique role of providing gap-filling auxiliary power at times of high demand or when the grid is otherwise under stress. 79 Fed. Reg. at 34,968 (“The power output from these simple cycle combustion turbines can be easily ramped up and down making them ideal for ‘peaking’ operations.”). No other form of power generation is capable of filling this role.

Combined cycle turbines are designed for baseload or intermediate load power, meaning that they are very efficient and have a high utilization rate. In contrast, simple cycle turbines provide peaking power. This means that their hours of operation are unpredictable, and they rarely operate at full load, the most efficient operating mode. The larger—and increasing—role that renewable power sources play requires significant support from simple cycle turbines, which can start-up quickly to compensate for highly variable and often intermittent generation from solar and wind facilities. These renewable energy facilities are subject to several factors beyond their control that impact their reliability, including, but not limited to fluctuating wind speeds, cloud cover, and even the approach of birds. As renewable energy takes on a larger share of power generation, the need for reliable and flexible simple cycle turbine operations will only increase. Indeed, the increased need for peaking power from simple cycle turbines may well be driven by this rulemaking, given EPA’s focus on increased renewable energy generation in Building Block 3. *See* 79 Fed. Reg. 34,866-70.

In the January 2014 proposal for newly constructed fossil fuel-fired EGUs, EPA reversed course and eliminated the previously proposed exemption for simple cycle turbines out of an unfounded fear that they will be used for baseload or intermediate load generation. 79 Fed. Reg. at 1459. This proposal includes the same applicability criteria for stationary combustion turbines as the January 2014 proposal. *See* 79 Fed. Reg. at 34,954 (proposed 40 C.F.R. § 5795(b)(2)). Simple cycle turbines are simply not interchangeable with combined cycle turbines in this way. As EPA recognizes, the use of simple cycle turbines for baseload power would involve much higher fuel and maintenance costs to generate the same amount of electricity as more efficient combined cycle turbines. Although no owner or operator would intend to run a simple cycle turbine for baseload power generation, as explained in more detail below, the changing nature of America’s electricity supply and the role of simple cycle turbines in providing power on an as-needed basis may require more flexibility in the future. In light of these important differences between simple cycle and combined cycle turbines, EPA should reinstate the exclusion for simple cycle turbines that it originally proposed in April 2012.

B. Alternatively, If EPA Must Regulate Simple Cycle Turbines, It Must Establish Separate and Achievable Standards of Performance

Should EPA determine that existing simple cycle turbines should be subject to the GHG emissions limits under Section 111(d), it should adjust the applicable emissions guidelines and

emission reduction targets to fully account for the projected future usage of these facilities as well as the emission reductions that they can achieve in practice.

1. Simple Cycle Turbines May Operate More Frequently as Renewable Power Generation Increases Amid Baseload Plant Retirements

EPA relies on data showing that only a small portion of simple cycle turbines met the proposed applicability criteria. *See* 79 Fed. Reg. at 34,895 n.260; *see also* 79 Fed. Reg. at 34,797 (asserting that only 0.2% of simple cycle turbines sold more than one-third of their potential electric output to the grid over a three-year averaging period). However, the data on which EPA relies dates back to 2000, 79 Fed. Reg. at 34,797, and does not account for the recent increases in renewable power generation and projections that this reliance on renewable power will increase due to the retirement of coal plants due to existing EPA regulations¹⁰⁰ or the changes in coal-fired electricity generating capacity and renewable energy generating capacity that would occur if this rule were finalized. Although EPA projects that existing NGCC facilities can increase generating capacity, new NGCC plants will be needed to replace at least some of the retired baseload power cause by this proposed rule, MATS, and other regulations. There is often a significant time lapse between planning and the actual start-up of operations due to burdensome and time-consuming State and federal regulations and lawsuits to block projects. This means that grid reliability will likely become more variable due to the increased use of renewable power and the expected time lag in replacing retired coal-fired electricity generation. Thus, it is likely that simple cycle turbines will have to be utilized more frequently than they have been in the past, both to provide grid stability until adequate non-renewable replacement baseload generation is in place and to accommodate increased reliance on intermittent renewable energy. Although most forecasts view future electricity demand as being relatively stable, the sources used to meet that demand are already beginning to change. Therefore, if EPA is intent on regulating existing simple cycle turbines, then it should do so in a way that accounts for the changes in operation that EPA's rules are likely to cause.

2. EPA Must Establish a Separate Subcategory for Simple Cycle Turbines

In the event that EPA withdraws the proposed rule and proceeds instead with source category-specific, inside the fence line emissions guidelines, it must establish a separate subcategory for existing simple cycle turbines. Simple cycle turbines—which operate at lower, less efficient loads and cannot use a heat recovery steam generator—cannot meet the same emission limits as NGCC turbines. EPA asserted in the January 2014 proposal that “advanced simple cycle combustion turbines have a *base load rating* of 1,150 lbs CO₂/MWh ...” 79 Fed. Reg. at 1485 (emphasis added) (citing EIA's Advanced Energy Outlook 2013 report). Thus, even under the most efficient operating conditions, the best performing simple cycle turbines cannot achieve the emissions limits that EPA has previously proposed for all stationary combustion turbines. And under the variable and less efficient conditions associated with the generation of peaking power, emissions will necessarily be higher. Further, given their role in

¹⁰⁰ *See* EIA, Annual Energy Outlook 2014, Early Release Overview at 2-3, 8, 11, 14-15, available at, [http://www.eia.gov/forecasts/aeo/er/pdf/0383er\(2014\).pdf](http://www.eia.gov/forecasts/aeo/er/pdf/0383er(2014).pdf).

providing peaking power, there are no technological advances that would allow simple cycle turbines to achieve the same emissions levels as NGCC turbines operating at or near full capacity. Combined cycle turbines increase efficiency and reduce emissions by capturing exhaust heat from the gas turbine and using it to produce additional electricity from a steam turbine. But when the heat recovery system and steam turbine are not operating, the NGCC facility essentially operates as a simple cycle turbine with a corresponding loss in efficiency. Thus, as long as simple cycle turbines are relied upon to provide peaking power, they cannot meet standards of performance designed for NGCC facilities.

If EPA determines that it is necessary to regulate simple cycle turbines under Section 111(d), it must account for these fundamental differences between simple cycle and NGCC turbines. Section 111 authorizes EPA to “distinguish among classes, types, and sizes within categories of new sources” when establishing standards of performance. 42 U.S.C. § 7411(b)(2). Section 111(d) gives EPA and the States further authority to base an existing source’s standard of performance on the source’s remaining useful life and other relevant factors. 42 U.S.C. § 7411(d)(1)(B). If simple cycle turbines are included as affected EGUs, EPA and the States could use this provision to establish different emissions guidelines and standards of performance for simple cycle turbines that reflect both the emission control technologies available to them and efficiency challenges associated with providing peaking power. Such an approach is fully consistent with Section 111(d) and would allow EPA to fully incorporate the different roles played by simple cycle and combined cycle turbines and the different emission reductions that can be achieved by each.

3. Applicability Should Be Based on a Source’s Intended Purpose at the Time of Construction, Not a *Post Hoc* Review of Actual Operations

To the extent that simple cycle turbines are treated as affected EGUs, it is also critical that EPA retain applicability criteria that address the source’s purpose at the time of construction. *See, e.g.*, proposed 40 C.F.R. § 60.5795(b)(2) (“was constructed *for the purpose of supplying ...* one third or more of its potential electric output and more than 219,000 MWh net-electrical output to a utility distribution system on a 3 year rolling average basis ...”). Under no circumstances should EPA base the applicability criteria solely on a facility’s actual utilization. As noted, simple cycle turbines are designed and operated to meet peaks in demand, providing stop-gap generation when needed. Although some peak demand times are predictable on a daily basis, interruptions in baseload power generation through forced outages or sub-optimal renewable generation can force greater utilization of peaking plants. Because simple cycle turbines have high fuel and maintenance costs, owners and operators do not construct (or modify or reconstruct) them with the intent to run them as baseload or even intermediate power sources. Yet, the unpredictable nature of their role could require peaking plants to run more than intended. Thus, subjecting them to regulation under Section 111(d) based solely on actual operations, would not only constrict the flexibility needed to ensure grid reliability, it will do so in a *post hoc* manner.

If the proposed rule is finalized in a manner that would subject simple cycle turbines to the Section 111(d) standards of performance based on the current utilization provisions, owners and operators could face an untenable position. Should unanticipated peaking power be required in a certain area, owners and operators would face the choice of shutting down the plants, potentially

resulting in brown outs, violations of contractual power supply agreements, and violations of NERC and ISO guidelines, or continuing operations and potentially becoming subject to three years worth of NSPS violations. Indeed, the very notion that owners and operators would be subject to an operation-based applicability test is absurd under the NSPS, which was designed to provide clear and predictable standards of performance for a given source category that would apply when a facility begins operations or is modified or reconstructed or when a Section 111(d) rule become effective. Instead of the proposed *post hoc* applicability standard, applicability should be based on the source's intended purpose at the time of construction and should also include an "emergency conditions exemption," as mentioned in the January 2014 proposal, 79 Fed. Reg. at 1497, provided that EPA can formulate a clear definition of what constitutes a "grid emergency." This will provide clarity to owners and operators and avoid the possibility that they will have to shut down in order to avoid alleged NSPS violations. Such an approach will also simplify the States' task in preparing implementation plans, as the States would not have to either develop contingency plans for changes in the status of simple cycle turbines or, alternatively, prepare new implementation plans based on changes in the utilization of simple cycle turbines.

XII. EPA MUST FULLY RECOGNIZE THE BENEFITS OF COMBINED HEAT AND POWER IN REDUCING GHG EMISSIONS IN THE ELECTRICITY SECTOR

In the event that EPA goes forward with the rule, the Associations appreciate EPA's continued recognition of the environmental benefits of combined heat and power ("CHP") units. For example, in the proposed rule for modified and reconstructed sources, EPA noted that "CHP requires less fuel to produce a given energy output, and because less fuel is burned to produce each unit of energy output, CHP reduced air pollution and greenhouse gas emissions. CHP has lower emissions rates and can be more economic than separate electric and thermal generation." 79 Fed. Reg. at 34,982. Likewise, Administrator McCarthy recently explained that "CHP technology offers a strategy to help meet the goals of the President's Climate Action Plan for a cleaner power sector while boosting the efficiency and competitiveness for many U.S. manufacturers."¹⁰¹ These statements echo EPA's prior observations that by capturing and utilizing "heat that would otherwise be wasted from the production of electricity," CHP generation produces significantly fewer CO₂ emissions than conventional boilers.¹⁰² In addition to increased efficiency, non-condensing generation CHP units consume little to no water in generating electricity and promote grid reliability through distributed generation.¹⁰³ EPA has predicted that an additional 50 GW of power, nearly half of that supplied by nuclear generating capacity, could be deployed by CHP units by 2020, resulting in significant emissions and cost

¹⁰¹ EPA, Press Release, EPA Honors Manufacturers with ENERGY STAR Award / Eastman Chemical, Janssen R and D, and Merck use Combined Heat and Power systems to cut carbon pollution, save money, and combat climate change (Sept. 30, 2014).

¹⁰² EPA, Combined Heat and Power Partnership, Environmental Benefits, *available at*, <http://www.epa.gov/chp/basic/environmental.html>

¹⁰³ See EPA, Combined Heat and Power: Frequently Asked Questions, *available at*, <http://www.epa.gov/chp/documents/faq.pdf>

reductions.¹⁰⁴ The U.S. Department of Energy is currently working with companies to significantly increase the amount of industrial distributed energy in the United States.

Given the environmental benefits of CHP units and the government's affirmative steps to promote increased industrial distributed generation, EPA should exclude industrial CHP units from the category of affected EGUs that are included in EPA's computation of State emission reduction goals and regulated under Section 111(d). Instead, it should permit industrial CHP units to participate voluntarily alongside other energy sources that can reduce net GHG emissions. First, such an exclusion would further incentivize the adoption and maintenance of efficient, reliable, and low-emission distributed generation. An exclusion would reflect the fact that industrial CHP units are fundamentally different from the fossil fuel-fired EGUs that are the subject of this rulemaking because their primary purpose is not to provide electricity to the grid. Second, industrial CHP units are typically customized to suit the needs of each host facility. This means that two CHP units will rarely balance the output of thermal energy and electricity production in the same manner. The oil and gas industry utilizes CHP units in both refining and upstream sectors, and the use of the electricity generated varies significantly by operation and facility. This characteristic is also typical for other sectors. Further, for any single unit, these balances may shift over any given time period. This variation among industrial CHP units makes them particularly unsuitable for uniform nation-wide BSER analyses or standards of performance. It also makes the calculation of thermal energy equivalence (conversion to kWh) impractical for reporting and enforcement purposes. As EPA has noted, 79 Fed. Reg. at 34,979, the use of third party-owned CHPs for adjacent industrial facilities only creates further complications. Therefore, the Associations request that EPA exclude industrial CHP units from the category of affected EGUs and from the calculation of State emission reduction targets.

We understand that it is not EPA's intention to regulate industrial CHP units. While excess electricity may be supplied to the grid, industrial CHP units are designed for the purpose of producing useful thermal and electric energy for the facility itself and the associated thermal host. Because they are not intended to provide a majority of their energy output to the public power grid they should not be regulated under this rule as commercial EGUs. Thus, if EPA proceeds to finalize emissions guidelines for existing fossil fuel-fired EGUs, the Associations suggest that EPA consider revising the applicability criteria for affected sources to exclude CHP units from the industrial and manufacturing sectors. While EPA could accomplish this exclusion in a number of ways, the Associations propose that EPA adopt the following text for 40 C.F.R. § 60.5795:

§ 60.5795 What affected EGUs must I address in my state plan?

- (a) The EGUs that must be addressed by your state plan are any affected steam generating unit, IGCC, or stationary combustion turbine that commences construction on or before January 8, 2014.
- (b) An affected EGU is a steam generating unit, integrated gasification combined cycle (IGCC), or stationary combustion turbine that meets the relevant applicability conditions specified in paragraph (b)(1) or (2) of this section.

¹⁰⁴ *Id.*

(1) A steam generating unit or IGCC that has a base load rating greater than 73 MW (250MMBtu/h) heat input of fossil fuel (either alone or in combination with any other fuel); was constructed for the purpose of supplying, and supplies more than 60% of its gross energy output as net-electric sales to a utility distribution system on a 3-year rolling average basis; and combusts fossil fuel for more than 10% of the heat input during a 3 year rolling average basis.

(2) A stationary combustion turbine that has a base load rating greater than 73 MW (250 MMBtu/h); was constructed for the purpose of supplying, and supplies more than 60% of its gross energy output as net-electric sales to a utility distribution system on a 3-year rolling average basis; combusts fossil fuel for more than 10% of the average annual heat input during a 3-year rolling average basis; and combusts over 90% natural gas on a heat input basis on a 3-year rolling average basis.

Alternatively, rather than modifying the general applicability criteria for affected EGUs, EPA could provide a specific exclusion for industrial CHP units. For example, EPA could state in the final rule that CHP units will not be considered to be affected EGUs if 20% or more of their total gross or net energy output consists of useful thermal output on a 3-year rolling average basis. This is the same threshold for useful thermal output that EPA has proposed to use for CHP units under its Section 111(b) proposals. *See, e.g.*, proposed 40 C.F.R. §§ 60.46(k) (definition of gross energy output); 60.4421 (same); 60.5580 (same).

Further, regardless of whether EPA permits CHP units to participate voluntarily at the compliance stage or fails to exclude them from the affected source category, it is essential that EPA and the States properly account for the carbon benefits of CHP. Thus, the Associations support EPA's proposal in the modified and reconstructed EGU rulemaking to make a technical correction to apply a discount for avoided electricity losses through transmission and recommend that such a discount be incorporated into any final Section 111(d) rule. *See* proposed 40 C.F.R. § 60.46(g). However, based on data from the U.S. Energy Information Administration, the discount should be increased from five percent to seven percent.¹⁰⁵ Further, the Associations

¹⁰⁵ U.S. Energy Information Administration, Frequently Asked Questions: How much electricity is lost in transmission and distribution in the United States? (reporting "about 7%") (<http://www.eia.gov/tools/faqs/faq.cfm?id=105&t=3>); *see also* U.S. Energy Information Administration, DOE/EIA-0348(01)/2, Jan 27, 2012, State Electricity Profiles 2012 (Table 10: "Supply and Disposition of Electricity, 2000 and 2004 through 2010 (Million Kilowatthours)") (<http://205.254.135.7/electricity/state/pdf/sep2010.pdf>; Table 10) (line losses calculated as ["estimated losses" divided by "total disposition" minus "direct use"]*100 or [261,990/(4,170,143-134,554)]*100 = 6.49%); EPA, Technical Support Document, State Plan Considerations: Technical Support Document at 50 (June 2014) ("According to EIA data, nationally, annual electricity transmission and distribution losses are equivalent to about seven percent of the electricity that is input to the transmission system in the United States."); EPA, Goal Computation Technical Support Document, at 17 (June 2014) ("The 7.51% scaling factor effectively converts the retail sales figure into a corresponding total net generation value that accounts for transmission and distribution losses") (<http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-goal-computation.pdf>).

urge EPA to fully count useful thermal output—as defined by EPA in its Section 111(b) proposals¹⁰⁶—toward gross energy output. In the proposed modified and reconstructed rule, EPA would only count 75% of useful thermal output toward gross energy output. 79 Fed. Reg. at 34,956-57. To fully account for the environmental benefits of CHP and to reflect the Administration’s efforts to promote CHP, EPA must count 100% of the useful thermal output from CHP facilities. Such an approach is also consistent with the past practice of EPA¹⁰⁷ and the States.¹⁰⁸

XIII. EPA’S ANALYSIS OF THE COSTS AND BENEFITS OF THE PROPOSED RULE IN THE REGULATORY IMPACT ANALYSIS IS ARBITRARY AND CAPRICIOUS

The proposed rule should also be withdrawn because EPA’s treatment of costs and benefits in the RIA is arbitrary and capricious. By simultaneously overestimating the potential benefits of the proposal and underestimating the costs, EPA erroneously suggests that the proposed rule will produce economic benefits. The Associations believe that an appropriately conducted cost-benefit analysis would reveal significant short- and long-term costs as a result of this proposal. First, EPA’s reliance on the social cost of carbon (“SCC”) is wholly inappropriate. While there are myriad problems with EPA’s social cost of carbon analysis, its treatment of international benefits and costs is particularly troubling here. Second, EPA fails to use full-economy modeling to evaluate employment impacts. Among other problems, this approach fails to account for the negative impact on employment likely to be experienced by the Associations’ non-utility members as a result of the proposed rule. Finally, EPA’s reliance on co-benefits from simultaneous reductions in pollutants other than GHGs is misplaced and must be revised to more appropriately reflect the health benefits that would actually be attributable to this proposed rule.

A. EPA’s Reliance On The Social Cost Of Carbon Is Arbitrary And Capricious And Overstates The Benefits Associated With Reducing CO₂ Emissions From EGUs

EPA’s reliance on the SCC approach developed by the Office of Management and Budget (“OMB”), EPA, and other federal agencies to estimate the benefits of reducing CO₂ emissions is arbitrary and capricious due to multiple flaws in OMB’s analysis. The Associations have previously documented those flaws in comments to OMB and incorporate those comments

¹⁰⁶ See Proposed 40 C.F.R. §§ 60.46(k), 60.4421, 60.5580, Docket # EPA-HQ-OAR-2013-0603-0044.

¹⁰⁷ See New Source Performance Standard (NSPS) for Stationary Combustion Turbines (40 CFR Part 60, Subpart KKKK) (crediting 100% of thermal output).

¹⁰⁸ See U.S. EPA, CHP Partnership, Feb. 2013, “Accounting for CHP in Output-Based Regulations,” at 7-9 (citing California’s multi-pollutant regulations and Texas permit by rule and standard permitting program) (<http://www.epa.gov/chp/documents/accounting.pdf>).

by reference.¹⁰⁹ Among the flaws in the SCC are the government’s opaque process and lack of transparency in formulating the SCC estimates (violating OMB’s own guidelines under the Information Quality Act), reliance upon modeling with inputs that lacked peer review, the failure to disclose and quantify key uncertainties involved in the modeling, the failure to incorporate potential benefits associated with increased temperatures, the reliance on low discount rates that inflate benefits compared to the 7-10% discount rates at which many business decisions are made, the failure to consistently apply present value adjustments to future costs and benefits, and the use of a global benefit estimate that severely limits the SCC’s utility. Thus, any reliance upon this deeply flawed policy—which is completely unreviewable for reasonableness or accuracy due to the government’s “black box” approach—is arbitrary and capricious.

Of particular concern for this rulemaking is EPA’s reliance on global benefits associated with reduced CO₂ emissions. EPA’s incorporation of global benefits grossly inflates the benefits of the rule, as only 7-10% of the projected global SCC benefits accrue to the United States.¹¹⁰ As an initial matter, EPA has failed to follow the proper procedures under the Clean Air Act for addressing international air pollution. Under Section 115, if EPA “has reason to believe that any air pollutant ... emitted in the United States cause[s] or contribute[s] to air pollution which may reasonably be anticipated to endanger public health or welfare in a foreign country ... [EPA] shall give formal notification thereof to the Governor of the State in which such emissions originate.” 42 U.S.C. § 7415(a). Upon making such a finding, EPA must direct the States to reduce those emissions through a revision of their State Implementation Plans (“SIPs”) pursuant to Section 110(a)(2)(H)(ii). *Id.* § 7415(b). There is no debate that EPA has failed to make the necessary findings or notifications required by Section 115. Thus, to the extent that EPA can regulate GHG emissions under Section 111(d), it cannot justify those regulations based on international benefits, as it has proposed to do here.

Further, EPA’s analysis of international effects is arbitrary and capricious because it only accounts for a portion of the international impacts that may occur. In particular, EPA makes no effort to account for potential international leakage of CO₂ emissions that may occur as a result of the rule. This is an issue of particular relevance to the Associations’ members. As explained in Section XVI., *infra*, many of the Associations’ energy intensive members are also trade exposed, meaning that even small changes in the costs for raw materials or other necessary inputs such as electricity can have a dramatic effect on the competitiveness of U.S. companies in comparison to their international peers. Given EPA’s projections for increased electricity prices, there is a substantial likelihood that at least a portion of the domestic emission reductions will be accomplished by shifting some industry and manufacturing—along with the associated CO₂ emissions—overseas. EPA must account for those emissions increases attributable to international leakage in the same manner as it accounts for domestic emissions decreases under a SCC approach. EPA’s failure to do so here renders the RIA arbitrary and capricious.

¹⁰⁹ See Comments of the Associations on the Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order No. 12866, Docket No. OMB-OMB-2013-0007-0100 (Feb. 26, 2014) (Attachment F).

¹¹⁰ See Interagency Working Group Technical Support Document at 11 (Feb. 2010).

B. EPA's Analysis Of The Employment Impacts Of The Proposed Rule Is Arbitrary And Capricious Because EPA Failed To Conduct Whole Economy Modeling

EPA's analysis of the employment impacts of the Proposed Rule is also arbitrary and capricious because EPA only evaluated employment impacts in a few select industries, while ignoring the larger employment impacts likely to be faced by many of the Associations' members. A rule as significant and complex as EPA's proposal will have diverse impacts on employment across a wide range of sectors. Those sectors that support coal-fired electricity generation, for example, will likely experience severe adverse effects on employment, as will the communities surrounding them. In addition, downstream employment effects on consumers of electricity are also likely to occur. EPA's partial economy model failed to address those impacts when it reported that the rule would have a positive net effect on unemployment. *See* 79 Fed. Reg. at 34,935. Had EPA conducted full economy modeling that addressed the full range of employment impacts on all affected sectors, it almost certainly would have reached a much different conclusion.

In prior comments to EPA and the Science Advisory Board ("SAB"), the Associations have explained the flaws in applying a partial economy model for substantial and wide-ranging rulemakings and the comparative benefits associated with conducting whole economy modeling.¹¹¹ The Associations incorporate those comments by reference. Unlike a partial economy approach, which focuses on a narrow subset of affected industry sectors, a whole economy approach focuses more broadly on the economic and employment impacts by taking into account the cascading effects of a regulatory change across interconnected industries and markets nationwide. To be effective in measuring employment and economic impacts across the entire U.S. economy, a whole economy model must include the following criteria. First, the model must include sufficient industry sector detail to evaluate both direct and indirect impacts. In other words, a model must not needlessly sacrifice depth of analysis to evaluate broad economy-wide impacts. Second, a model must include sufficient detail at the regional level to identify changes in the regional distribution of output and employment, which may add additional costs on industry due to relocation of labor and capital. Third, a model must include international trade flows to evaluate how regulations will affect tradable sectors. This is of particular importance for the Associations' trade exposed members who are subject to strong foreign competition. Fourth, a model should include dynamic analyses to examine adjustments in labor and capital markets in response to regulations over time. Static analyses that consider only a single time frame can mask key impacts that can occur over time.

Had EPA included a more robust whole economy model in its RIA, the Associations are confident that the model would have presented a much different picture of potential employment impacts. EPA has applied a whole economy model on only two prior occasions, the Clean Air Interstate Rule and the Clean Air Visibility Rule and Best Available Retrofit Technology Guidelines and, in each case, EPA reported no projected employment growth in response to the

¹¹¹ U.S. Chamber of Commerce, *et al.*, Comments on Draft Supporting Materials for the Science Advisory Board Panel on the Role of Economy –Wide Modeling in the U.S. EPA Analysis of Air Regulations, Docket ID: EPA-HQ-OA-2014-0129-0009 (Attachment G).

regulations.¹¹² In contrast, EPA’s more recent partial economy models have consistently predicted large gains in employment as a result of environmental regulations.¹¹³ EPA’s recent Mercury & Air Toxics Rule is an example. Using a partial economy model, EPA predicted that the rule would create 8000 long-term jobs and 46,000 jobs during the implementation period. In contrast, a whole economy model constructed by NERA shows initial job losses of 180,000 or more with long-term reductions of at least 50,000 jobs.¹¹⁴ This significant discrepancy shows the importance of conducting a detailed whole economy model, and casts doubt on the validity of EPA’s employment conclusions that are based on a less rigorous partial economy model.

C. EPA’s Inclusion of Co-Benefits From Reducing Criteria Pollutants Is Arbitrary, Capricious, and Unlawful

While EPA asserts that the proposed rule will have significant positive net benefits, a significant portion of the benefits identified by EPA are derived from the co-benefits associated with reductions of criteria pollutants. EPA notes in the RIA that reducing CO₂ emissions from the electricity sector will also have the effect of reducing emissions of SO₂, NO₂, and directly emitted PM_{2.5}, which will, in turn, reduce ambient concentrations of PM_{2.5} and ozone. RIA at ES-9. Depending on the discount rate that is applied, these co-benefits can be as much as an order of magnitude greater than the benefits associated with reducing CO₂ emissions alone. In other words, it is the co-benefits—not CO₂ reductions—that support EPA’s assertion that the rule would produce net benefits. But it is arbitrary, capricious, and unreasonable for EPA to justify the rule based on ancillary or unintended benefits. If EPA seeks to regulate a pollutant under Section 111, it must demonstrate that health and environmental benefits from reducing emissions of that pollutant will be cost-effective. *See* 42 U.S.C. § 7411(a)(1) (directing EPA and the States to “tak[e] into account the cost of achieving such reduction ...”). In addition, EPA’s reliance on co-benefits from reducing emissions of criteria pollutants is particularly problematic because EPA is barred from directly regulating criteria pollutants under Section 111(d). *Id.* § 7411(d)(1) (prohibiting EPA from using Section 111(d) to regulate “any existing source for any air pollutant ... for which air quality criteria have not been issued or which is not included on a list published under [42 U.S.C.] section 7408(a)”). EPA’s approach here would allow it to indirectly regulate criteria pollutants from a source category by finding a surrogate air pollutant that can be regulated under Section 111(d). If EPA moves forward with this rule, it must justify it solely on the domestic benefits of reducing CO₂ emissions, a standard that EPA is unlikely to meet.

D. EPA Must Conduct A Review Of The Proposed Rule’s Impact On Small Businesses Under The Regulatory Flexibility Act

Before proceeding further with this rulemaking, EPA must convene a Small Business Advocacy Review panel and conduct a regulatory flexibility analysis to evaluate the proposed

¹¹² NERA Economic Consulting, *Estimating Employment Impacts of Regulations: A Review of EPA’s Methods for Its Air Rules* 3 (Feb. 2013).

¹¹³ *Id.*

¹¹⁴ *Id.* at 29.

rule's impact on small businesses. Under the Regulatory Flexibility Act and Small Business Regulatory Enforcement Fairness Act, EPA must "prepare and make available for public comment an initial regulatory flexibility analysis ... [that] describe[s] the impact of the proposed rule on small entities." 5 U.S.C. § 603(a). Rather than conducting the necessary analysis, EPA has instead "certif[ied] that this action will not have a significant economic impact on a substantial number of small entities" because States, not EPA, are ultimately responsible for implementing Section 111(d). 79 Fed. Reg. 34,946. Not only is this a myopic view of EPA's obligation under the Regulatory Flexibility Act, it is plainly incorrect in light of EPA's expansive view of its own authority under Section 111(d).

First, as an initial matter, EPA recognizes that the proposed rule would result in average increases in electricity prices by as much as seven percent. 79 Fed. Reg. at 34,934. Electricity costs are a significant concern for many small businesses and are a top three business expense for 35% of all small businesses.¹¹⁵ This alone demonstrates the widespread impact that the proposed rule would have on small businesses. Second, by proposing a beyond the fence line BSER analysis that includes emission reductions by electricity consumers and a portfolio approach that allows direct regulation of entities outside the regulated source category, EPA has virtually ensured that small businesses will be regulated under the proposed rule. In fact, given the lack of practical flexibility available to States to achieve the aggressive emission reduction targets proposed by EPA, Section 111(d) implementing agencies will likely have no choice but to impose legally binding energy efficiency obligations on electricity consumers, including many small businesses. The virtual certainty of these regulatory obligations distinguishes this rulemaking from the flexibility afforded to States in NAAQS rulemakings where Courts have said that regulatory flexibility analyses were not required. *See* 79 Fed. Reg. at 34,947 (citing *Am. Trucking Assoc. v. EPA*, 175 F.3d 1027, 1043-46 (D.C. Cir. 1999)). Again, withdrawal of the proposal is warranted so that EPA can convene a Small Business Advocacy Review panel and prepare a regulatory flexibility analysis before proceeding with a new proposal under Section 111(d).

XIV. COMMENTS ON IMPLEMENTATION

For the reasons discussed above, EPA's proposed rule is arbitrary, capricious, and contrary to law and should be withdrawn. However, in the alternative, if EPA decides to go forward with this rulemaking, the Associations have a number of practical concerns related to the States' implementation of the proposed emission reduction goals. Without waiving any of their legal arguments, the Associations offer the following comments to ensure that any final rule adopted by EPA, as well as any subsequent implementation plans, are fully informed by comments from interested stakeholders and ensure that any emission reductions are undertaken in a reasonable and cost-effective manner.

¹¹⁵ National Federation of Independent Business, Energy, *available at* <http://www.nfib.com/advocacy/energy/>.

A. State Implementation Plans Should Give Affected EGUs Voluntary Flexibility To Determine How To Achieve Emission Reductions

While the States and EPA are prohibited from imposing binding GHG emission reduction obligations on any entities other than affected EGUs, *see* Section VIII., *supra*, if EPA goes forward with the rule, the Associations agree that States should have flexibility to incorporate voluntary opportunities to reduce net GHG emissions that are broader than those used in the BSER analysis. To establish a feasible and cost-effective State implementation plan, States must give affected EGUs the flexibility to incorporate low-cost emission reductions that can be accomplished by electricity consumers or other third parties who are taking action to reduce net GHG emissions. At the same time, however, EPA and the States must always make clear—both in these regulations and in State implementation plans—that third-party participation in such emission reduction programs is on a voluntary basis. By making participation voluntary, EPA and the States can ensure that no third-party entity inadvertently becomes subject to regulatory obligations without its consent. Thus, any legally binding monitoring and verification obligations that are necessary for third-party participation in the State implementation process will only be incurred by those entities that evaluate the participation costs, determine that the overall impact of participation is beneficial, and voluntarily assent to those legal obligations.

In contrast to the BSER analysis conducted by EPA and the States, which must focus exclusively on affected EGUs, existing fossil fuel-fired EGUs should be given broad flexibility to look beyond the fence line to identify opportunities to reduce GHG emissions through voluntary agreements with other entities. Providing affected EGUs with such flexibility, where available and appropriate, in achieving GHG emission reductions is economically efficient and will allow existing facilities to reduce CO₂ emissions through lower-cost emission reduction opportunities that can be adopted voluntarily by third parties. While the form would likely vary between State plans, a central feature must be the ability for entities other than affected EGUs to voluntarily participate in the program alongside affected EGUs, either by joining a centralized exchange program or through direct agreements with individual EGUs.¹¹⁶ In either context, the third parties would be able to choose to obtain compensation for taking voluntary, cost-effective measures to reduce GHG emissions. The end result, which is cost-effective emission reductions, is consistent with the general theme of the Clean Air Act because it sets emission standards that are achievable inside the fence line of the facility without dictating how a specific facility must achieve them. It is also consistent with Section 111(d) specifically because it takes into account the cost of achieving emission reductions.

The Associations urge EPA and the States to incorporate as broad a position as possible with respect to such voluntary compliance mechanisms to identify low-cost opportunities to reduce GHG emissions. Thus, the Associations agree with EPA that electricity transmission and distribution efficiency improvements, the use of biomass-derived fuels, and new NGCC units should be available as voluntary compliance options that can be included in State implementation plans. *See* 79 Fed. Reg. at 34,923. To the extent that new, cost-effective

¹¹⁶ Companies with diverse electricity generating portfolios may also be able to reach such agreements internally, for example, by constructing new renewable energy units in lieu of completing retrofits at existing coal-fired EGUs.

technological advances occur, new emission control technologies could also be included. *See id.* In addition, once they are appropriately removed from the BSER analysis, the emission reduction opportunities identified by EPA in Building Blocks 2-4 would remain eligible from a compliance perspective on a voluntary basis. Thus, deviations from least-cost dispatching, new renewable and nuclear generating capacity, and demand-side energy efficiency improvements would all be eligible for voluntary participation in a State implementation plan. For example, performance-based contracts (“PCs”) for energy savings would offer a proven mechanism for reducing electricity consumption and lowering GHG emissions. Under a PC arrangement, energy service companies (“ESCOs”) install new energy efficiency equipment at customer facilities which are paid off over time with the resulting savings from the customers’ utility bills. EPA should expressly authorize States to include PCs as a compliance option and provide clear guidance on how States could incorporate PCs into their implementation plans. Further, as explained in Section XII., *supra*, any industrial CHP units that are excluded from the rule’s applicability criteria would also be eligible to participate on a voluntary basis. The Associations also urge EPA to look beyond the sources identified thus far and explicitly endorse carbon offsets as a viable, low-cost method of reducing net GHG emissions for voluntary participants. Finally, to the extent feasible, States should have the flexibility to incorporate existing GHG reduction programs into their State implementation plans, provided, again, that no additional obligations are imposed on entities other than affected EGUs.

Moreover, the Associations believe that EPA’s proposal to give affected facilities the flexibility to reduce GHG emissions through voluntary partnerships with third parties can serve as a model for other programs under the Clean Air Act. In other instances, the Clean Air Act gives regulated sources broad flexibility to achieve emission reductions once EPA sets an emission limit based on the relevant legal standard. Thus, even when an emission limit is derived from a technology-based standard such as the best available control technology (“BACT”) standard under the PSD program, a facility is simply assigned an emissions limit, and is not obligated to install the technology on which the permitting authority relied so long as the facility does not exceed its assigned emission limits.

B. EPA’s Proposal Inappropriately Limits States’ Ability To Rely On Existing Programs To Reduce CO₂ Emissions

In the proposed rule, EPA would inappropriately limit States’ ability to rely on emission reductions attributable to existing programs. Specifically, EPA states that “for an existing state requirement, program, or measure, a state may apply toward its required emission performance level the emission reductions that existing state programs and measures achieve during a plan performance as a result of actions taken after the date of this proposal.” 79 Fed Reg. at 34,918. However, EPA provides that “this proposed limitation will not apply to existing renewable energy requirements, programs and measures because existing renewable energy generation prior to the date of the proposal of the emission guidelines was factored into the state-specific CO₂ goals as part of building block 3.” *Id.* n.293. This approach arbitrarily and capriciously excludes valuable emission reduction measures undertaken by first movers.

The Associations agree with EPA that existing renewable energy programs should be applied toward achieving State emission reduction targets. However, it is arbitrary and capricious for EPA to exclude other existing State programs to reduce GHG emissions that are

equally capable of reducing net CO₂ emissions from the electricity sector. In setting the State emission reduction targets, EPA relied on more than existing renewable energy programs. For example, with respect to demand-side energy efficiency, EPA relies on the EERS established by 12 States in its BSER analysis and then used each States' current annual incremental savings rate to establish their starting point during the interim compliance period. *Id.* at 34,872-73. Thus, for all practical purposes, EPA relied on existing EERS in the same manner as existing RPS when calculating the State-specific emission reduction goals, and it would be arbitrary and capricious for EPA to fail to give them the same status it has proposed for existing RPS programs. Furthermore, there is no reason to limit the applicability of existing State programs to those on which EPA relied in setting State emission reduction targets. EPA repeatedly emphasizes the flexibility that must be afforded to States under Section 111(d), but here EPA undermines that flexibility by excluding other innovative State programs that may reduce a State's overall GHG emissions. Finally, by setting an arbitrary cutoff point at the time of EPA's proposal, the Agency is effectively punishing those States who were early adopters of programs and other measures to reduce GHG emissions. Instead, EPA should commend those States for their early action to reduce GHG emissions by allowing them to incorporate those programs into State implementation plans.

C. EPA's Criteria For Acceptable Offsets In A State Plan To Be "Additional" Is Arbitrary And Unnecessary And Will Penalize Affected Sources For Making Investment Decisions That Reduce GHGs Prior To The Establishment Of The State Plans

The Associations agree with EPA that out-of-sector offsets can provide flexibility to States that seek to reduce GHG emissions, 79 Fed. Reg. at 34,881, and are encouraged by EPA's statement that "emission limits for affected EGUs that are included in state plans could still include provisions that provide the ability to use GHG offsets for compliance with emission limits," *id.* at 34,910. However, EPA appears to apply this concept in an arbitrary manner by incorporating a so-called "additionality" requirement:

A key criterion that must be met for the award of offset allowances or credits is a demonstration that the offset project is "additional" (i.e., that it would not have occurred absent the incentive provided through the award of the offset allowance or credit).

EPA, Projecting EGU CO₂ Emission Performance in State Plans Technical Support Document at 40 n.47 (June 2014).

This discretionary policy determination by EPA arbitrarily excludes those entities that have made investment decisions since the 2012 baseline year that were based, in part, in anticipation of regulatory programs such as this one to reduce GHG emissions. For example, a corporation could be faced with a decision between upgrading a coal-fired powerhouse to meet upcoming regulations for criteria pollutants and/or HAPs or converting it to natural gas combustion. A member company of one of the Associations faced such a decision, and, while the net present values of the alternatives were very close, it elected to convert to natural gas due, in part, to its expectation that GHG credits would one day be of some value. Under EPA's policy, EPA would not allow these credits to be considered "additional" because they were made in

anticipation of this rule rather than in response to it. Such an outcome is inherently unfair and unnecessarily penalizes those early movers that make their investment decisions in advance of regulatory programs. EPA should discourage this approach as it serves as a significant disincentive to early action.

A State should not be arbitrarily barred by EPA from incorporating out-of-sector offsets into its implementation plan simply because the offset credits were generated before EPA's proposal was issued. Allowing such offsets affords States that select a market-based trading program with the flexibility to most cost-effectively meet their emission reduction targets. Where such offsets can be accurately measured and sold "apples-for-apples" to affected EGUs, there is no rational basis to exclude them from State implementation plans. Further, since GHGs are global pollutants, EPA and the States should consider measures that would allow multi-State companies that generate offsets to use them in any State where they have affected EGUs that are regulated under Section 111(d). Likewise, EPA should explicitly permit the use of international offsets under the same conditions that it permits domestic offsets. Such an approach would not only reflect the way in which existing State GHG reduction plans operate, but would also allow companies to reduce GHG emissions in a cost-effective manner.

D. Any Sources Regulated by States Under A Portfolio Approach Must Be Exempted From Or Given Credit Toward Compliance With Any Subsequent GHG Regulations Under Section 111 For Their Source Category

If EPA proceeds to finalize guidelines that permit States to adopt a portfolio approach, it must also include adequate protections to ensure that entities regulated under a portfolio approach are not unfairly penalized if EPA subsequently expands the NSPS program to other source categories. As discussed above, many of the Associations' members are among the nations' largest consumers of electricity and, as a result, may be the focus of State-imposed demand-side energy efficiency measures under a portfolio approach. At the same time, EPA has indicated that it will consider establishing Section 111 GHG standards of performance for additional source categories that would affect the Associations' members. *See* U.S. Environmental Protection Agency Fiscal Year 2015 Justification of Appropriation Estimates for the Committee on Appropriations (seeking appropriations to consider GHG emission limits for petroleum refining, pulp and paper facilities, municipal solid waste landfills, iron and steel production, animal feeding operations, and Portland cement manufacturing). Thus, in theory, if a portfolio approach is permitted here, a source could be subject to regulation under NSPS standards of performance for multiple source categories.

As a result, it is imperative that EPA address this potential risk in the final rule if it decides to permit a portfolio approach. First, in order to avoid unnecessary and duplicative regulation, EPA should include a provision that exempts such affected entities from future standards of performance issued under Section 111 if they are subject to legally binding emission reductions under a State implementation plan pursuant to this rulemaking. As a legal matter, there is no basis to suspect that Congress would have intended that a single source be subject to more than one standard of performance under Section 111(d). Further, as a practical matter, subjecting a source to multiple standards of performance will add unnecessary administrative and compliance costs and will create the potential that a source will be subject to inconsistent or even incompatible regulatory obligations.

At a minimum, however, EPA must ensure that sources subject to regulation under a Section 111(d) portfolio approach will receive full credit for GHG emission reduction activities if new standards of performance for GHG emissions are imposed. This is particularly true if EPA or a State adopts percentage-based standards of performance as it has proposed for modified fossil fuel fired EGUs (*i.e.*, requires a source to reduce emissions to x percent below some historical average). Because the emission reduction approaches identified in a BSER analysis are likely to be similar to those that would be targeted in a State portfolio approach, there is a substantial likelihood that sources located in States that adopt a portfolio approach would have already implemented some or all of the pollution control technologies identified in a subsequent BSER analysis. Again, it would be arbitrary and capricious to require a source to complete additional pollution control measures if it has already installed the measures that EPA identifies as BSER in a future rulemaking. Instead, EPA must give a source full credit for those emission reductions in any future standard of performance for GHG emissions under Section 111.

E. EPA Must Give The Public An Opportunity To Review And Comment On Federal Rules For Measuring And Verifying Energy Efficiency And Renewable Energy Credits Before Finalizing This Rule

Emission reductions related to energy efficiency and renewable energy are likely to play a significant role in compliance with the Section 111(d) standards of performance for fossil fuel-fired EGUs, regardless of whether EPA proceeds with the Building Block BSER analysis or gives affected EGUs flexibility to voluntarily incorporate such emission reductions for the purpose of complying with more narrow standards of performance for each source category based on an inside the fence line BSER analysis. In either case, it is critical that energy efficiency and renewable energy programs can be measured and verified. However, EPA has provided no guidance on how such measurements and verifications must be made. Without additional information about how emission reductions associated with these sources will be measured and verified, the Associations cannot comment on the technical bases for including these emission reduction opportunities, and States will ultimately be unable to develop implementation plans that incorporate them. This is a serious deficiency with respect to two significant aspects of EPA's proposed standards of performance.

To ensure that the measurement and verification of energy efficiency and renewable energy programs are incorporated into the final rule in an appropriate manner, it is imperative that EPA conduct a rulemaking to establish the necessary procedures. Further, because of their importance to this rulemaking, EPA must issue a proposed rule addressing measurement and verification and solicit public comment on it before finalizing this rule. Such an approach will, at a minimum, give States some initial guidance regarding the incorporation of energy efficiency and renewable energy into their implementation plans. Given EPA's abbreviated schedule for the States to prepare such implementation plans, failure to provide some initial guidance to States at an early stage will pose significant challenges to the States' ability to develop satisfactory implementation plans that address these two subjects within the time allotted by EPA.

F. EPA Must Provide Clarity And Guidance Regarding Mass-Based Emissions Targets

In the event that EPA proceeds with a State-wide emission reduction target and offers States the option of converting their rate-based target into a mass-based target, *see* 79 Fed. Reg. at 34,892, it is imperative that EPA provide additional guidance to the States on how such a conversion should be done. In the proposed rule, EPA offers virtually no detail in the record as to how such a mass-based conversion should be conducted. Without additional detail, the Associations cannot effectively comment on this aspect of EPA's proposal. In particular, there are a number of challenges that must be addressed in converting EPA's rate-based approach into a mass-based approach. As an initial matter, because the rule includes obligations that extend to 2030 and beyond, it is critical both to develop a reasonable estimate of growth in electricity demand and a process for recalibrating the mass-based standard over time if projections about demand growth prove to be incorrect. Projections of future demand growth are further complicated by their overlap with EPA's expectations regarding demand-side energy efficiency, which will also affect future growth. Further, a straightforward conversion from rate to mass is not possible here because the denominator in EPA's calculation of the rate-based limit includes several components that reflect avoided emissions rather than electricity generation. Likewise, for some categories such as nuclear generation, only a portion of electricity generation is included. Again, these factors complicate the conversion process. Without more detail from EPA as to how a mass-based conversion would be conducted, the Associations cannot fully comment on this aspect of the proposed rule, and ultimately States will face challenges in including a mass-based conversion in their implementation plans if they lack any guidance from EPA as to what conversion process will be deemed satisfactory.

Further, EPA's eleventh-hour release of a technical support document for the conversion to mass-based targets¹¹⁷ fails to cure the defect in the proposed rule. EPA has given States and other interested stakeholders less than a month to evaluate and comment on this technical support document. This is far too little time given the potential significance of this issue, particularly for States that have already adopted market-based GHG emissions limits under State law. Moreover, even a cursory review of the document reveals that it fails to address a number of the concerns highlighted above. To ensure that EPA's rulemaking process is transparent and fully informed by public comment, it is imperative that EPA develop—and accept comment on—a more robust guidance for conversion to mass-based targets. Further, after considering those public comments, EPA must finalize such guidance documents concurrent with this rulemaking. As explained in Section II.A., *supra*, EPA has proposed a compressed time period for States to prepare and submit implementation plans. As a practical matter, States seeking to use a mass-based approach will not be able to prepare satisfactory implementation plans without knowing how to conduct a mass-based conversion. Thus, without sufficient guidance from EPA, the mass-based compliance option will become largely illusory.

¹¹⁷ EPA, Translation of the Clean Power Plan Emission Rate-Based CO₂ Goals to Mass-Based Equivalents: Technical Support Document (Nov. 2014); *see also* 79 Fed. Reg. 67,406 (Nov. 13, 2014).

G. The Associations Support EPA’s Proposal To Measure Compliance With Emissions Targets With Multi-Year Compliance Periods

If EPA decides to proceed with State-wide emission reduction targets, the Associations urge EPA to incorporate sufficient flexibility to ensure that any short-term, unforeseen challenges will not prevent the States from achieving their emission reduction targets. First, the Associations agree with EPA that compliance with the final emission reduction goals should use a three-year rolling average. *See* 79 Fed. Reg. at 34,953 (proposed 40 C.F.R. § 60.5775(d)). As EPA is aware, EGU efficiency and emissions rates can vary over time, with relatively predictable patterns over the course of a year. Thus, at a minimum, the compliance period must be measured in years. However, in a State-wide plan, EPA must also account for potential deviations from expected electricity demand—such as the unusually cold winter in 2014—that can alter projected electricity use and dispatching and, therefore, overall emissions rates. Likewise, EPA must account for the potential for longer-term outages at individual facilities due to routine maintenance or unexpected malfunctions that can also alter projected electricity dispatching over long periods of time. Adopting a multi-year compliance option will reduce the noise in yearly emissions data and help ensure that States do not fail to comply with the State-wide emission reduction targets due to unforeseen events outside of their control.

For the same reasons, if EPA elects to retain the interim compliance period, the Associations support EPA’s proposal to have a single compliance period covering the entire interim period. *Id.* (proposed 40 C.F.R. § 60.5775(c)(2)). In addition to the year-to-year challenges described above, State-wide emissions during the interim period will be even more unpredictable, as States, affected EGUs, and potentially voluntary third-party participants will all be undertaking efforts to reduce emissions each year during the interim period. No matter how carefully a State may plan its trajectory toward compliance with the final standards, it is unreasonable to expect that States will be able to strictly adhere to targets set by EPA or by the States in their implementation plans. EPA’s proposed two-year incremental compliance periods are too short to account for the inevitable deviations that will occur during implementation. *See id.* (proposed 40 C.F.R. §60.5775(c)(1)). While the Associations do not believe that incremental compliance periods are needed at all, under no circumstances should EPA adopt an incremental period that is shorter than five years. Anything shorter will add unnecessary regulatory complexity for States with sound implementation plans that nevertheless experience short-term challenges.

XV. OTHER COMMENTS

A. The Associations Agree With EPA That CCS Is Not BSER For Existing Fossil Fuel-Fired EGUs

The Associations agree with EPA that partial CCS should not be considered BSER for existing coal-fired EGUs. 79 Fed. Reg. at 34,876. In their comments on EPA’s January 2014 proposal for newly constructed sources, the Associations explained in detail that CCS technology is not an adequately demonstrated system of emission reduction for newly constructed coal-fired EGUs. Associations’ NSPS Comments at 12-29.¹¹⁸ Specifically, the Associations explained that

¹¹⁸ These comments are incorporated herein by reference.

there are no such commercial-scale, coal-fired EGUs currently in existence and that EPA's reliance on heavily subsidized, pilot-scale facilities and under construction, commercial-scale EGUs was unwarranted. The Associations also identified a number of implementation challenges associated with CO₂ transport and storage which were not adequately addressed by EPA. The issues raised by the Associations in those comments are equally relevant here. Further, as EPA recognizes, design constraints, site-specific limitations, and a lack of proximity to potential geologic storage sites would make retrofitting existing sources with CCS technology more difficult. 79 Fed. Reg. at 34,876. Thus, EPA was correct to conclude that partial CCS is not BSER and that any BSER analysis for coal-fired EGUs should be limited to heat rate improvements.

B. EPA's Failure To Provide The Public With Key Supporting Data Is Unlawful

The Associations and other interested stakeholders are unable to provide meaningful comments on the proposed rule because EPA has unlawfully withheld key data on which it purports to rely for the proposed standards of performance. Section 307(d) states that “[a]ll data, information, and documents referred to in this paragraph on which the proposed rule relies shall be included in the docket on the date of publication of the proposed rule.” 42 U.S.C. § 7607(d). Thus, failure to properly docket the data and analysis on which a proposed rule is based constitutes a violation of the Clean Air Act. *Union Oil Co. v. EPA*, 821 F.2d 678, 683 (D.C. Cir. 1987). The requirement to provide data and analyses goes to the heart of an agency's obligation to give interested stakeholders the opportunity to “participate in a meaningful way in the discussion and final formulation of rules.” *Conn. Light and Power Co. v. NRC*, 673 F.2d 525, 528 (D.C. Cir. 1982) (citing *Ethyl Corp.*, 541 F.2d at 48). “In order to allow for useful criticism, it is especially important for the agency to identify available technical studies and data that it has employed in reaching the decision to propose particular rules. To allow an agency to play hunt the peanut with technical information, hiding or disguising the information that it employs is to condone a practice where the agency treats what should be a genuine exchange as mere bureaucratic sport.” *Id.* at 530. EPA's compliance with this obligation is critical because, under the CAA, only objections to a proposed rule that are “raised with reasonable specificity” during the comment period can be included in a petition for review. *See* 42 U.S.C. § 7607(d)(7)(B).

EPA's proposed rule violates Section 307(d) because it did not include in the docket—in a clear and transparent manner—the data and analyses on which it relied to set the proposed standards of performance for modified and reconstructed coal- and natural gas-fired EGUs. These concerns were raised by other interested stakeholders well before the comment period closed, but have not been remedied by EPA. *See, e.g.*, Comments of Patrick Morrissey, West Virginia Attorney General, Office of Attorney General State of West Virginia, *et al.* (Aug. 25, 2014), Docket ID EPA-HQ-OAR-2013-0602-14062. Among the deficiencies in the proposed rule is EPA's failure to include necessary information on more than a handful of the modeling runs it conducted while developing the rules. Specifically, EPA developed integrated planning model runs for five different scenarios over five different time frames but failed to include in the docket all of the necessary information to allow the Associations to evaluate the results reported by EPA. Likewise, EPA failed to include in the docket sufficient information to allow the Associations to verify EPA's claims regarding year-by-year improvements in heat rate efficiency. EPA has a legal obligation under Section 307(d) to allow all interested parties to review and provide meaningful comments on the documents that form the basis for EPA's

rulemaking. It has not done so here. It would be unlawful for EPA to finalize this rule without producing all of the data and analyses on which it relies and then giving the Associations and other interested stakeholders an opportunity to review and comment on those documents.

C. EPA Must Base The Final Rule On Representative Baseline Data

The Associations are also concerned that the 2012 baseline that EPA uses to calculate the State emission reduction targets may not be representative of a broader range of conditions under which EGUs may operate in the future. Changes in economic conditions, weather, and relative prices of energy feedstocks can all affect the amount of electricity that is generated in a given year as well as the allocation among different energy sources. Thus, adopting a multi-year baseline may prove to be more representative because it can smooth out some of the year-to-year variability that occurs in the electricity sector. The Associations support EPA's decision in the NODA to release additional data for 2010 and 2011. 79 Fed. Reg. at 64,553. However, given the limited time between the release of the NODA and the close of the comment period, the Associations have not been able to fully evaluate the new data or make a recommendation with respect to an appropriate baseline. Therefore, we urge EPA to consider reopening the comment period or issuing a supplemental rulemaking as necessary to ensure that interested stakeholders have sufficient time to evaluate and comment on the appropriate baseline for this rulemaking.

D. EPA Cannot Rely On Facilities That Received Funding Under The Energy Policy Act Of 2005

EPA's BSER analysis is also unlawful to the extent that it relies on projects that have received funding under the EPAct of 2005. Without providing any supporting information, EPA states in the proposed rule that "EPA is aware of the potential that one or more facilities involved in programs mentioned in or relied upon in this proposal may have received some form of assistance under the Energy Policy Act of 2005." 79 Fed. Reg. at 34,856. Given the EPAct of 2005's focus on experimental technologies, it is not surprising that Congress recognized the program's inconsistency with the legal standards for establishing NSPS and prohibited the use of such programs to establish that a technology is adequately demonstrated:

No technology, or level of emission reduction, solely by reason of the use of the technology, or the achievement of the emission reduction, by 1 or more facilities receiving assistance under this Act, shall be considered to be adequately demonstrated for purposes of Section 111 of [the Clean Air Act].

42 U.S.C. § 15962(i)). Section 1307 of the EPAct, outlining the treatment of tax credits for qualifying advanced coal projects, includes a nearly verbatim prohibition on the EPA Administrator's consideration of CCPI-funded projects under Section 111 of the Clean Air Act. 26 U.S.C. § 48A(g). The Associations have previously commented on EPA's

purported justification for relying on facilities that had received EPOA of 2005 funding and incorporate those comments by reference.¹¹⁹

The EPOA of 2005 prohibits EPA from considering evidence from projects funded under that act in setting “standard[s] of performance” under Section 111 of the CAA if, in the absence of such projects, EPA cannot establish that the NSPS control technology is “adequately demonstrated.” In other words, EPA is required by statute to conduct a “but for” analysis to determine whether the control technology would qualify as BSER but for evidence from projects funded under the EPOA of 2005. If not, EPA cannot rely on the control technology in establishing a standard of performance. Otherwise EPA could avoid the statutory limitations imposed by Congress simply by referring generally to other non-EPOA of 2005-funded projects, even if those other projects would be insufficient to establish that a given control technology qualified as BSER. Such an interpretation would frustrate Congress’ purpose in passing the EPOA of 2005 and would contradict the plain language of the statute.

Therefore, when a proposed or final NSPS must rely on evidence from projects funded by the EPOA of 2005 to be justified, such projects necessarily constitute the “but for” basis for the standard and are effectively the sole support for the control technology. Here, in the proposed rule, EPA proposes to do exactly what the EPOA of 2005 prohibits: it states that it is relying on projects that were funded under the EPOA of 2005, but fails to identify which projects received such funding or conduct the necessary “but for” analysis to determine if they are the sole support for the technology EPA relies on to establish BSER.

EPA claims that it is free to consider EPOA of 2005-funded projects so long as it “does not depend solely upon those projects, and the [adequately demonstrated] determination remains adequately supported without any information from” EPOA of 2005 projects.” See 79 Fed. Reg. at 34,856 (citing EPA, Notice of Data Availability (NODA), 79 Fed. Reg. 10,750 (Feb. 26, 2014)). EPA’s expansive interpretation of the word “solely” creates a loophole so large that it essentially swallows the rule. EPA asserted in association with the January 2014 proposal that, while it cannot rely exclusively on EPOA of 2005-funded projects, the projects can “provide part of the basis for” an adequately demonstrated determination.¹²⁰ In other words, according to the EPA, as long as the Agency can point to some other shred of supporting evidence, it is permitted to rely on EPOA of 2005-funded projects to show that a control technology is adequately demonstrated under Section 111. This contorted interpretation of the EPOA of 2005 is *clearly* contrary to the statute and to Congressional intent as described above, and places virtually no limit on the EPA’s ability to rely on EPOA of 2005-funded projects. Indeed, that is the case here. Rather than explaining the role that EPOA of 2005-funded projects played in EPA’s BSER

¹¹⁹ American Chemistry Council, *et al.*, Comments on Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units, Notice of Data Availability (May 9, 2014), Docket ID: EPA-HQ-OAR-2013-0495-10503.

¹²⁰ EPA, Technical Support Document: Effect of EPOA2005 on BSER for New Fossil Fuel-fired Boilers and IGCCs at 13 (Jan. 8, 2014), *available at* http://www2.epa.gov/sites/production/files/2014-01/documents/2013_proposed_cps_for_new_power_plants_tsd.pdf.

analysis, EPA simply states in passing in a footnote that some EPCRA of 2005 projects may have been considered. Given Congress' clear mandate here, EPA cannot make broad statements about the quality of its BSEER analysis without providing interested stakeholders the necessary tools, such as the identities of EPCRA of 2005-funded projects, to verify its assertions. EPA has failed to do so here, and the proposal, if finalized would be unlawful under the EPCRA of 2005.

E. EPA Must Apply the Same Applicability Criteria in Each of the Proposed Rules

The proposed rule also creates uncertainty for existing sources by proposing applicability criteria for existing sources that differ from those proposed for newly constructed, modified, and reconstructed sources. Section 111 is a source category-based provision, and, once EPA determines that regulations are necessary, it must establish standards of performance for new, modified, and reconstructed sources in that source category under Section 111(b). Standards of performance can only be established for existing sources if they belong to a source category that is already regulated under Section 111(b). Having determined the appropriate source categories under the January 2014 proposal, EPA cannot define the source category differently here. Indeed, because Section 111(d) only applies to existing sources "to which a standard of performance under this section would apply if such existing source were a new source," 42 U.S.C. § 7411(d)(1), it would be unlawful for EPA to define the source category more broadly here by adopting more expansive applicability criteria. Yet, by proposing applicability criteria for coal-fired EGUs that eliminate the 10% fossil fuel threshold, as well as the requirement that facilities actually supply more than one third of their potential electric output and more than 219,000 MWh net-electric output to the grid on an annual basis, EPA has done just that. *Compare* 79 Fed. Reg. at 34,954 (proposed 40 C.F.R. § 5795(b)(1)), *with* 79 Fed. Reg. 1502 (proposed 40 C.F.R. § 60.64(a)).¹²¹ EPA offers no justification in the proposed rule for eliminating these applicability criteria, and the Associations urge EPA to conform the applicability criteria for existing sources under Section 111(d) to the proposed applicability criteria for newly constructed sources under Section 111(b).

F. EPA Cannot Cure Defects In The Proposed Rule Through The Untimely Submission of Support Documents

In an attempt to cure defects in the content of its original proposal, EPA has published notices of data availability and technical support document on October 30, 2014 and November 13, 2014. 79 Fed. Reg. 64,543; 79 Fed. Reg. 67,406. These new documents raise a series of complex, new issues regarding both EPA's BSEER analysis and the procedures for States to submit implementation plans. Providing full and complete responses to the myriad issues raised by EPA in these documents will require extensive research and cannot be completed in the few

¹²¹ EPA further complicates this issue by proposing different applicability requirements for modified and reconstructed sources under Section 111(b). *See* EPA-HQ-OAR-2013-0603-0044; *also available at* <http://www2.epa.gov/carbon-pollution-standards/proposed-carbon-pollution-standards-modified-and-reconstructed-power>; EPA-HQ-OAR-2013-0603-0047, *also available at* <http://www2.epa.gov/carbon-pollution-standards/proposed-carbon-pollution-standards-modified-and-reconstructed-power>.

weeks provided by EPA. For this reason, the Associations requested an extension of the comment deadline in order to respond more completely to EPA's proposals. On November 18, 2014 EPA denied that request. The lack of time provided by EPA has prevented the Associations and other interested stakeholders from receiving a full and fair opportunity to comment on the proposed rule. For this reason, the Associations urge EPA to reopen the comment period for this rule to give interested stakeholders the additional time necessary to respond to the issues raised in the NODA and technical support documents and how they relate to EPA's proposed rule.

In the NODA, EPA identifies a number of potential problem areas in the proposed rule, and solicits comment on options for addressing those problems. Many, if not all, of the challenges identified by EPA in the NODA can be attributed to the complexity associated with EPA's decision to look beyond the fence line in its BSER analysis. Yet, rather than using stakeholder feedback to simplify the proposal, EPA has identified alternative approaches that would further complicate an already complex regulation. For example, rather than eliminating the interim compliance period, EPA proposes alternative glide-paths that would be based on detailed State- and source-specific data and assumptions. 79 Fed. Reg. at 64,548-59. Likewise, EPA's proposed solution to the current disparity in existing NGCC capacity is to adopt a complex regional structure for its BSER analysis. *Id.* at 64,550-51. EPA also proposes a complex regional structure for calculating and allocating renewable energy potential among the States in an effort to address concerns over interstate transmission and interstate sale of renewable electricity credits. *Id.* at 64,551-52. Finally, EPA suggests that differences in the proposed treatment between renewable energy and energy efficiency and NGCC facilities can be resolved by increasing even further the displacement of coal-fired electricity generation. Thus, if adopted, EPA's suggested alternatives would address the complexity and implementation challenges of the proposal by increasing, rather than decreasing, the complexity and stringency of the proposal.

Further, rather than providing concrete proposals in the NODA, EPA solicits comment on a wide range of issues identified thus far by stakeholders. For example, EPA solicits comment "on whether to establish some minimum value as a floor for the amount of generation shift for purposes of building block 2 ... [and] on what that value should be." *Id.* at 64,550. Likewise, with respect to an alternative regional approach for renewable energy under Building Block 3, EPA solicits comment on "what the regional structure would be," on "the criteria that should be used to reapportion state RE targets within a given region," and on "what components of the state RE targets should be regionalized." *Id.* at 64,551. These requests for comment, among others in the NODA, are so broad that they would be more appropriate for an advanced notice of proposed rulemaking. To the extent that EPA decides to adopt any of the alternative options described in the NODA, EPA must engage in a supplemental rulemaking process that presents EPA's proposal in concrete terms and gives the public a full and fair opportunity to comment on that proposal.

XVI. EPA SHOULD NOT EXPAND GHG NSPS TO OTHER SOURCE CATEGORIES

EPA has indicated that it is considering GHG new source performance standards for other source categories. *See, e.g.*, U.S. Environmental Protection Agency Fiscal Year 2015

Justification of Appropriation Estimates for the Committee on Appropriations, March 2014.¹²² For a number of reasons, the Associations believe that even if EPA were to finalize standards of performance for GHG emissions from fossil fuel-fired EGUs, it should not proceed with additional GHG standards of performance for other source categories.

As an initial matter, there is no legal obligation to do so. The NSPS Settlement Agreement for Petroleum Refineries (“Refinery Settlement Agreement”),¹²³ for example, is crystal clear.¹²⁴ It does not impose any legal requirements to impose a GHG NSPS for petroleum refineries, Refinery Settlement Agreement ¶ 9,¹²⁵ nor does it “limit or modify the discretion accorded EPA,” *id.* ¶ 11. Beyond the lack of legal obligation, EPA should exercise that discretion to not propose GHG standards of performance for other source categories for all of the reasons set forth below.

There are fundamental and overarching distinctions between EGUs and other source categories in the manufacturing sector that warrant a different approach to regulating GHG emissions. GHG emissions from individual manufacturing source categories are at least an order of magnitude lower than those from EGUs, significantly altering the cost-benefit and endangerment and significance equations. If EPA’s rudimentary cost-benefit analyses in this proposal and the January 2014 proposal are to be taken at face value, one could conclude that the proposed Section 111(b) rules would have minimal costs and benefits, while this proposed rule would produce net benefits. While the Associations disagree with EPA’s conclusions in these proposed rules, *see* Section XIII., *supra*, it would clearly not be appropriate to make a similar conclusion in other contexts. Other source categories are impacted by a much broader range of factors, such as industry economics, geography, federal and State incentives, transportation networks, ownership structures, foreign competitors, profit margins, and customer bases. All of these factors must be considered, necessitating a fundamentally different approach than that taken for EGUs.

Regulating GHG emissions from the manufacturing sector is neither prudent nor necessary. Many industries have already taken aggressive, voluntary actions to reduce GHG

¹²² Available at http://www2.epa.gov/sites/production/files/2014-03/documents/fy2015_congressional_justification.pdf.

¹²³ Available at <http://www2.epa.gov/sites/production/files/2013-09/documents/refineryghgsettlement.pdf>.

¹²⁴ The Refinery Settlement Agreement was entered in response to lawsuits by several States and environmental petitioners challenging EPA’s 2008 NSPS for petroleum refineries and alleging that EPA should have included standards of performance for GHG emissions. *Id.* at 1.

¹²⁵ While the parties identified dates by which EPA would propose and finalize NSPS for GHG emissions from refineries, *id.* ¶¶ 2, 3, the agreement explained that “the dates stated in Paragraphs 2 and 3 shall be construed to represent only the parties’ attempt to compromise claims in litigation, and not to represent agreement that any particular schedule for further agency action is reasonable or otherwise required by law,” *id.* ¶ 9.

emissions through energy efficiency initiatives—the only available option to reduce GHG emissions from most manufacturing source categories. Aside from raw materials, energy use is the single largest cost to many manufacturing operations. A commitment to identify and implement cost-effective energy efficiency initiatives has been a primary driver of the continued competitiveness of domestic manufacturing. Unlike power generators, the domestic manufacturing sector faces heightened global competition. Thus, manufacturers already understand that reducing expenditures on energy usage in the manufacturing process is of the utmost importance. Given industry’s own interest and significant investment in improving energy efficiency, it is unlikely that there are significant cost-effective opportunities that have not already been exploited by manufacturers on a voluntary basis.

Expanding Section 111 standards of performance to other source categories will compound the stifling effect of regulatory overreach on the manufacturing sector. The manufacturing sector will already be impacted from the widespread consequences of such regulations on the EGUs, including less abundant and diverse energy sources and higher energy costs. New compliance costs associated with standards of performance for GHG emissions for the manufacturing sector will only compound these impacts. The regulations will have the immediate effect of diverting resources away from long-term investments that can improve the economy and provide environmental benefits in order to pay for higher immediate compliance costs and higher energy prices. The ripple effect will extend to the entire value chain, with negative and far reaching economic consequences with little benefit to the environment.

New source performance standards are an especially inefficient way to impose GHG emission reductions due to their one-size-fits-all application. Many manufacturing sectors, unlike EGUs, are trade exposed and face stiff competition from overseas. New regulations with significant compliance costs that fail to account for trade exposure will simply result in significant and irreversible job losses without reducing global GHG emissions. To the extent that overseas facilities operate in less regulated conditions, global GHG emissions will actually increase. This is why Congressional proposals to regulate GHG emissions have generally provided for protections to domestic industries that are trade exposed. Executive Order 13563 embodies similar principles, requiring regulations to promote economic growth, competitiveness and job creation by achieving regulatory ends through the least burdensome means. 76 Fed. Reg. 3,821 (Jan. 21, 2011). Given existing PSD regulations and the significant potential costs to the manufacturing sector, including reduced international competitiveness, leakage through trade, and job losses, EPA should not proceed with additional GHG standards of performance.

Should EPA decide to consider standards of performance for GHG emissions for other sectors—over the strong objections of the Associations—it should first proceed with an advanced notice of proposed rulemaking for each sector it proposes to regulate that provides significant lead time for the Agency to solicit views and comments from all impacted stakeholders and make a source-category specific endangerment determination for GHG emissions. This would allow EPA enough time to understand the complex and varied energy requirements and manufacturing processes involved for each source category prior to proposing a rule having an unannounced impact. An advanced notice of proposed rulemaking would also obviate the need to create dubious legal fictions, such as the “transitional source” category for certain newly constructed sources and claims that modified and reconstructed sources are not “new sources” under Section 111. A “sleight of hand” offered to mitigate the costs of a

rulemaking only promotes uncertainty, prolongs the regulatory process through litigation, and discourages economic development.

CONCLUSION

The proposed rule is arbitrary, capricious, and unlawful for the reasons set forth above. The EPA should immediately withdraw the proposed rule. Should the EPA wish to consider regulating GHGs emissions from existing fossil fuel-fired EGUs under Section 111(d), it should first issue an advanced notice of proposed rulemaking in order to foster an open, unbiased dialogue with all affected and interested parties.

The undersigned Associations appreciate the opportunity to comment on this proposal.

American Chemistry Council

American Forest & Paper Association

**American Fuel & Petrochemical
Manufacturers**

American Iron and Steel Institute

American Petroleum Institute

American Wood Council

Brick Industry Association

Corn Refiners Association

Council of Industrial Boiler Owners

Electricity Consumers Resource Council

National Association of Home Builders

National Association of Manufacturers

National Lime Association

National Oilseed Processors Association

Portland Cement Association

The Fertilizer Institute

U.S. Chamber of Commerce

ATTACHMENT A

Testimony of Philip D. Moeller
Commissioner, Federal Energy Regulatory Commission
Senate Committee on Energy & Natural Resources
Hearing on “Keeping the Lights On- Are We Doing Enough to Ensure the Reliability
and Security of the U.S. Electric Grid?”
April 10, 2014

Chairman Landrieu, Ranking Member Murkowski, and members of the Committee, thank you for inviting me to testify regarding the continued reliability of our nation’s bulk power system. I am Philip D. Moeller, and I have been a Commissioner at the Federal Energy Regulatory Commission since 2006.

Every day, men and women sit in windowless control rooms making decisions on how to operate the power grid. They ensure that the right power plants are running at the right time, and they carefully balance power generated with power consumed. On a minute-to-minute basis, they ensure that the lights, heaters and air conditioners stay on, and that manufacturing and other business activity continues. This winter had more than a few days when electricity supplies were at their limits, yet the operators kept the system running without interruption. Every one of us today owe each of them appreciation for their hard work. And going forward, we owe them the resources that they need to keep the lights on in the future.

I have long-stated that I can be “fuel-neutral” but I cannot be “reliability-neutral”. That is, I can be neutral as a regulator with regard to how competitive markets ultimately decide which types of power plants are most efficient and affordable, regardless of whether those power plants are fueled by water, natural gas, fuel oil, uranium, coal, wind, the sun or any other fuel. But I cannot be neutral about the reliability of our electricity.

In preparing today’s testimony I reviewed the positions that I have presented to Congress over the years on the subject of the reliability. For more than three years I have worked on the reliability implications of our nation’s unprecedented transition in the fuels we are using to generate electricity. Sufficient and reliable electricity is necessary for both economic opportunity and the heating and cooling that are essential to the health and safety of our nation’s citizens. An insufficient or unreliable supply of electricity endangers economic recovery and can be a matter of life and death during periods of extreme heat or cold.

Specifically in order to prepare for today, I reviewed the letter that I sent to Senator Murkowski in August 2011 in response to her questions about the reliability implications of environmental rules impacting the nation’s generation fleet. I also reviewed my testimony to the Energy and Power Subcommittee of the House Energy and Commerce Committee dated September 14, 2011. In both documents, I called for a more formal analysis of electric reliability implications of these rules, potentially including the Commission, the Environmental Protection Agency (EPA), the US Department of Energy, the North American Electric Reliability Corporation (NERC), and regional market participants. As far as I know, this formal analysis never commenced.

I was, and remain concerned that EPA's analysis greatly underestimated the amount of power production that would be retired due to these rules. I reiterate today what I stated then: I am not opposed to closing older and less environmentally-friendly power plants, but I am concerned that the compressed timeframe for compliance with the new environmental rules was not realistic given the amount of time it takes to construct new plants and energize transmission upgrades to mitigate plant closures. In addition, EPA's analysis failed to analyze whether there was sufficient transfer capability to move power from areas of energy surplus to areas short of power. Given that public policy aspirations cannot violate the laws of physics, we need to act carefully in transforming the power grid.

After two unusually warm winters in most of the country, our latest winter exposed an increasingly fragile balance of supply and demand in many areas in the Eastern Interconnection. Prices at times were extraordinarily high and consumers used more power because of the cold weather, which multiplied the impact of higher prices. Consumers are now beginning to receive utility bills that in some cases are reportedly several times what they paid during similar periods in previous years. Although the operators of the power grid worked hard to keep the system working, the experience of this winter strongly suggests that parts of the nation's bulk power system are in a more precarious situation than I had feared in years past.

In approximately 53 weeks, coal plants that do not employ specific emission-control technology will be closed. Those plants undergoing retrofits have the option to request a one-year extension. Those particular plants will also have the option of requesting an additional year for compliance, although this option comes with the uncertainty of being subject to civil litigation for violating the Clean Air Act during the additional year.

Regarding the structure of our electricity markets, our nation consists of different regions with unique market structures and varying mixes of fuels used to generate this electricity. New England and California are increasingly reliant on natural gas as a fuel to generate electricity, while much of the Mid-Atlantic, Southern and Midwestern regions rely more on coal, and my home of the Pacific Northwest relies heavily on hydropower. Thus the impact of environmental rules on generation resources and constraints in fuel supply chains differ across the nation.

Although there has been attention focused on the loss of coal-fired generation, nuclear plants are under increasing economic pressure to close as a result of record low capacity prices. In addition to several announced nuclear plant closures, some utilities have predicted additional retirements if specific units are unable to operate profitably. Losing these plants has long-term implications both to the reliability of the system and on the nation's emission profile.

To the extent that a region has other resources, the retirement of power plants may not have a material impact on consumers. Yet the experience of this past winter indicates that the power grid is now already at the limit. Heading into the next several years, some regions of the nation will be more vulnerable to supply shortages than others. It is vitally important to recognize, as this latest winter demonstrated, that weather is a significant variable in terms of electricity demand. We can hope for

mild winters and summers over the next several years, but hoping for mild weather is not a practical method of planning to meet economic growth and public safety.

For example, the Midwest is struggling to understand whether or not it will have sufficient capacity to handle peak weather over the next few years. In particular, in the region served by the Midcontinent Independent System Operator (MISO), the reserve margin is now expected to be at a deficit of approximately 2 Gigawatts (GW) in the Summer of 2016. Although this figure has been revised downward from a projected deficit of approximately 6 GW a few months ago, the new figure assumes that consumers will collectively reduce their electricity consumption every year by approximately .75 percent. Again, weather will play a role in the actual rate of consumption, as will the strength of economic (and especially industrial) recovery in the region.

In addition to looking at MISO collectively, specific locations across the Midwest may have more significant problems. For example, the Upper Peninsula of Michigan has long depended on a coal plant to serve local customers, but at this time, it is not clear how that part of the state will receive electricity service in the future. Regulators, including FERC, are considering this matter, but resolving regulatory issues is only one step in the process of building infrastructure. That is, infrastructure still needs to be built after the regulators conclude their processes, and that takes time.

Other regions of the country face similar problems, and executives at the utilities have various levels of confidence in their ability to promise the delivery of power on the hottest and coldest days of the year. Some executives are very confident in the ability of the power grid to handle the new environmental regulations, and other executives are hopeful that the weather will be mild. But beyond relying on the confidence of utility executives, as a FERC Commissioner with responsibility for the reliability of the grid nationwide, I need actual data on which power plants are retiring, and which resources will be ready to replace those retiring plants. To date, obtaining reliable data and thoughtful analysis as to the changing generation mix and its consequences has been a challenge.

Moreover, advocates for strong environmental rules promise that nothing they do will threaten reliability. And they promise to get their rules right. But on the other hand, advocates for traditional sources of power assert that the rules are not right, and that reliability may be threatened. These differing viewpoints can be tested with data.

In preparing this testimony, I sought the latest data from the various regions on the power plants being retired, and the resources that are replacing them. Lots of data are available, and some of them are contradictory. But lacking in that data is any guarantee that this nation will continue its history of reliability on the coldest and hottest days of the year. While nobody can guarantee future reliability, we can do better in understanding the risks and issues facing the power grid in the future. As the history of my testimony before Congress demonstrates, the sufficiency of our generating resources has been clouded by uncertainties arising from changing environmental regulation. While we have been sensitive to the fragility of our electric infrastructure in certain pockets of the country, this winter has demonstrated that our margin of surplus generation is narrower and more constrained than many understood. Together, industry and the federal government can do better in devoting resources to

looking carefully at individual power plants that are expected to retire, the load they serve, and the strategies being used to replace those power plants.

In conclusion, our nation is undergoing an unprecedented change in the electricity sector in a very compressed time frame. I continue to believe a more formal review process is necessary including the Commission, the EPA, and non-government entities to analyze the specific details of retiring units as well as the new units and new transmission that will be needed to manage this transition so as to best assure reliability of the nation's electricity sector.

Thank you again for the opportunity to testify, and I look forward to answering any questions from members of the Committee.

ATTACHMENT B

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Potential Reliability Impacts of EPA's Proposed Clean Power Plan

Initial Reliability Review
November 2014

RELIABILITY | ACCOUNTABILITY



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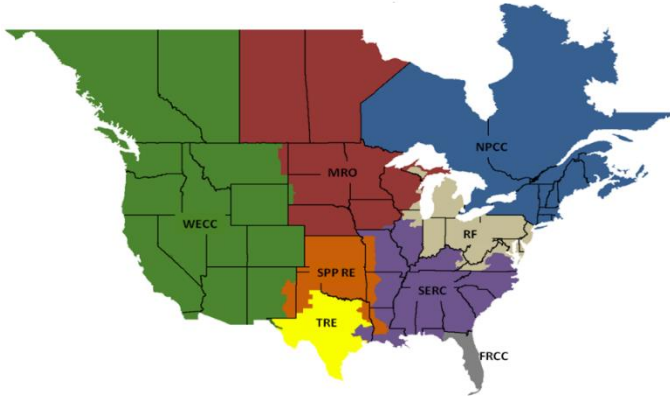
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Preface

The North American Electric Reliability Corporation (NERC) has prepared the following assessment in accordance with the Energy Policy Act of 2005, in which the United States Congress directed NERC to conduct periodic assessments of the reliability and adequacy of the bulk power system (BPS) in North America.¹ NERC operates under similar obligations in many Canadian provinces, as well as a portion of Baja California Norte, Mexico.

NERC is an international regulatory authority established to evaluate and improve the reliability of the BPS in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term (10-year) reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC is the electric reliability organization (ERO) for North America, subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada.²

NERC Regions and Assessment Areas



FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
SPP-RE	Southwest Power Pool Regional Entity
TRE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

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¹ H.R. 6 as approved by the One Hundred Ninth Congress of the United States, the [Energy Policy Act of 2005](#). The NERC Rules of Procedure, Section 800, further detail the Objectives, Scope, Data and Information requirements, and Reliability Assessment Process requiring annual seasonal and long-term reliability assessments.

² As of June 18, 2007, FERC granted NERC the legal authority to enforce Reliability Standards with all U.S. users, owners, and operators of the BPS and made compliance with those standards mandatory and enforceable. Equivalent relationships have been sought and for the most part realized in Canada and Mexico. Prior to adoption of §215 in the United States, the provinces of Ontario (2002) and New Brunswick (2004) adopted all Reliability Standards that were approved by the NERC Board as mandatory and enforceable within their respective jurisdictions through market rules. Reliability legislation is in place or NERC has memoranda of understanding with provincial authorities in Ontario, New Brunswick, Nova Scotia, Québec, Manitoba, Saskatchewan, British Columbia, and Alberta, and with the National Energy Board of Canada (NEB). NERC standards are mandatory and enforceable in Ontario and New Brunswick as a matter of provincial law. Manitoba has adopted legislation, and standards are mandatory there. In addition, NERC has been designated as the “electric reliability organization” under Alberta’s Transportation Regulation, and certain Reliability Standards have been approved in that jurisdiction; others are pending. NERC standards are now mandatory in British Columbia and Nova Scotia. NERC and the Northeast Power Coordinating Council (NPCC) have been recognized as standards-setting bodies by the Régie de l’énergie of Québec, and Québec has the framework in place for Reliability Standards to become mandatory. NEB has made Reliability Standards mandatory for international power lines. In Mexico, the Comisión Federal de Electricidad (CFE) has signed WECC’s reliability management system agreement, which only applies to Baja California Norte.

Executive Summary

The Environmental Protection Agency (EPA), on June 2, 2014, issued its proposed Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, commonly referred to as the proposed Clean Power Plan (CPP), under Section 111(d) of the Clean Air Act, which introduces CO₂ emission limits for existing electric generation facilities. On August 14, 2014, the NERC Board of Trustees directed NERC to develop a series of special reliability assessments to examine the proposed CPP. This report is NERC's initial reliability review of the potential risks to reliability, based on the assumptions contained in the proposed CPP.

NERC maintains a reliability-centered focus on the potential implications of environmental regulations and other shifts in policies that can impact the reliability of the bulk power system (BPS). Reliability assessments conducted while the EPA is finalizing the CPP can inform regulators, state officials, public utility commissioners, utilities, and other impacted stakeholders of potential resource adequacy concerns, impacts to system characteristics (such as essential reliability services (ERSs)), and, to some degree, areas that are more likely to require power-flow-related transmission enhancements to comply with NERC Reliability Standards. The goals of this review are listed in more detail below:

- Provide an evaluation and comparison of the assumptions supporting the CO₂ reduction objectives in the proposed CPP against other reported projections available within NERC assessment reports.
- Provide insight into planned generation retirements, load growth, renewable resource development, and energy efficiency measures that might impact CO₂ emissions and the EPA's target-driven assumptions.
- Provide insight into the potential reliability consequences of either the target-driven emission assumptions or the NERC projection-based assumptions and, in particular, the potential reliability implications if the EPA assumptions cannot be realized.
- Identify potential reliability impacts resulting from the expected resource mix changes, such as coal resource displacement or retirements, the impacts on regional planning reserve margins, the shifts in resource mix and ERS characteristics, the increase in variable resources, the concentration of resources by fuel source (especially natural gas), transmission and large power transfers, and other reliability characteristics, including regional differences.
- Support the electric power industry and NERC stakeholders by providing an independent assessment of reliability while serving as a platform to inform policy discussions on BPS reliability and emerging issues.

This report and its findings are *not* intended to: (1) advocate a policy position in regard to the environmental objectives of the proposed CPP; (2) promote any specific compliance approach; (3) advocate any policy position for a utility, generation facility owner, or other organization to adopt as part of compliance, reliability, or planning responsibilities; (4) support the policy goals of any particular stakeholder or interests of any particular organization; or (5) represent a final and conclusive reliability assessment.

The objective of this review is to identify the reliability implications and potential consequences from the implementation of the proposed CPP and its underlying assumptions. The preliminary review of the proposed rule, assumptions, and transition identified that detailed and thorough analysis will be required to demonstrate that the proposed rule and assumptions are feasible and can be resolved consistent with the requirements of BPS reliability. This assessment provides the foundation for the range of reliability analyses and evaluations that are required by the ERO, RTOs, utilities, and federal and state policy makers to understand the extent of the potential impact. Together, industry stakeholders and regulators will need to develop an approach that accommodates the time required for infrastructure deployments, market enhancements, and reliability needs if the environmental objectives of the proposed rule are to be achieved.

Herein, NERC examines the assumptions made in the EPA's four Building Blocks:³

Building Block 1: Heat rate improvements

Building Block 2: Dispatch changes among affected electric generating units (EGUs)

Building Block 3: Using an expanded amount of less-carbon-intensive generating capacity

³ [Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units.](#)

Building Block 4: Demand-side energy efficiency

NERC identified the following factors as requiring additional reliability consideration:

Implementation of the CPP reduces fossil-fired generation: The proposed CPP aims to cut CO₂ emissions from existing power plants to 30 percent below 2005 levels by 2030. Under the EPA proposal, substantial CO₂ reductions are required under the State Implementation Plans (SIPs) as early as 2020. According to the EPA's *Regulatory Impact Assessment*, generation capacity would be reduced by between 108 and 134 GW by 2020 (depending on state or regional implementations of Option 1 or 2).⁴ The number of estimated retirements identified in the EPA's proposed rule may be conservative if the assumptions prove to be unachievable. Developing suitable replacement generation resources to maintain adequate reserve margin levels may represent a significant reliability challenge, given the constrained time period for implementation.

Assumed heat rate improvements for existing generation may be difficult to achieve: NERC is concerned that the assumed improvements may not be realized across the entire generation fleet since many plant efficiencies have already been realized and economic heat rate improvements have been achieved. Multiple incentives are in place to operate units at peak efficiency, and periodic turbine overhauls are already a best practice. Site-specific engineering analyses would be required to determine any remaining opportunities for economic heat rate improvement measures.

Greater reliance on variable resources and gas-fired generation is expected: The CPP will accelerate the ongoing shift toward greater use of natural-gas-fired generation and variable energy resources (VERs) (renewable generation). Increased dependence on renewable energy generation will require additional transmission to access areas that have higher-grade wind and solar resources (generally located in remote areas). Increased natural gas use will require pipeline expansion to maintain a reliable source of fuel, particularly during the peak winter heating season. Pipeline constraints and growing gas and electric interdependency challenges impede the electric industry's ability to obtain needed natural gas services, especially during high-use horizons.

Rapid expansion of energy efficiency displaces electricity demand growth through 2030: In its rate calculation for best practices by state, the EPA assumes up to a 1.5 percent annual retail goal for incremental growth in efficiency savings. The EPA assumes that the states and industry would rapidly expand energy efficiency savings programs from 22 TWh/year in 2012, to 108 TWh/year in 2020, and reach 380 TWh/year by 2029. With such aggressive energy efficiency expansion, the EPA assumes that energy efficiency will grow faster than electricity demand, with total electricity demand shrinking after 2020. The implications of this assumption are complex. If the EPA-assumed energy efficiency growth rates cannot be attained, additional carbon reduction measures would be required, primarily through reduced fossil-fired generation.

Essential Reliability Services may be strained by the proposed CPP: The anticipated changes in the resource mix and new dispatching protocols will require comprehensive reliability assessments to identify changes in power flows and ERSs. ERSs are the key services and characteristics that comprise the following basic reliability services needed to maintain BPS reliability: (1) load and resource balance; (2) voltage support; and (3) frequency support. New reliability challenges may arise with the integration of generation resources that have different ERS characteristics than the units that are projected to retire. The changing resource mix introduces changes to operations and expected behaviors of the system; therefore, more transmission and new operating procedures may be needed to maintain reliability.

More time for CPP implementation may be needed to accommodate reliability enhancements: State and regional plans must be approved by the EPA, which is anticipated to require up to one year, leaving as little as six months to two years to implement the approved plan. Areas that experience a large shift in their resource mix are expected to require transmission enhancements to maintain reliability. Constructing the resource additions, as well as the expected transmission enhancements, may represent a significant reliability challenge given the constrained time period for implementation. While

⁴ Regional implementation of Option 2 assumes 108 GW of retirements (includes CC, Coal, CT, Nuclear, O/G, and IGCC) by 2020. State implementation of Option 1 assumes 134 GW of retirements (includes CC, Coal, CT, Nuclear, O/G, and IGCC) by 2020. For additional information, see: Regulatory Impacts Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants (June 2014) and supporting [IPM Model](#) documentation and data.

the EPA provides flexibility for meeting compliance requirements within the proposed time frame, there appears to be less flexibility in providing reliability assurance beyond the compliance period.

A summary of NERC’s initial reliability review recommendations is provided below:

General Recommendations

1. **NERC should continue to assess the reliability implications of the proposed CPP** and provide independent evaluations to stakeholders and policy makers.
2. **Coordinated regional and multi-regional industry planning and analysis groups should immediately begin detailed system evaluations to identify areas of concern** and work in partnership with policy makers to ensure there is clear understanding of the complex interdependencies resulting from the rule’s implementation.
3. **If the environmental goals are to be achieved, policy makers and the EPA should consider a more timely approach** that addresses BPS reliability concerns and infrastructure deployments.

Recommendations to Address Direct Impacts to Resource Adequacy and Electric Infrastructure

Fossil-Fired Retirements and Accelerated Declines in Reserve Margins

The Regions, ISO/RTOs, and states should perform further analyses to examine potential resource adequacy concerns.

Transmission Planning and Timing Constraints

The EPA and states, along with industry, should consider the time required to integrate potential transmission enhancements and additions necessary to address impacts to reliability from the proposed CPP. The EPA and policy makers should recognize the complexity of the reliability challenges posed by the rule and ensure the rule provides sufficient time for the industry to take the steps needed to significantly change the country’s resource mix and operations without negatively affecting BPS reliability.

Regional Reliability Assessment of the Proposed CPP

Other ISO/RTOs, states, and Regions should prepare for the potential impacts to grid reliability, taking into consideration the time required to plan and build transmission infrastructure.

Reliability Assurance

The EPA, FERC, the DOE, and state utility regulators should employ the array of tools and their regulatory authority to develop a reliability assurance mechanism, such as a “reliability back-stop.” These mechanisms include timing adjustments and granting extensions where there is a demonstrated reliability need.

Recommendations to Address Impacts Resulting from the Changing Resource Mix

Coal Retirements and the Increased Reliance on Natural Gas for Electric Power

Further coordinated planning between the electric and gas sectors will be needed to ensure a strong and integrated system of fuel delivery and generation adequacy. Coordinated planning processes should include considerations for pipeline expansion to meet the increased reliance on natural gas for electric generation, especially during extreme weather events (e.g., polar vortex).

The Changing Resource Mix and Maintaining Essential Reliability Services

ISO/RTOs, utilities, and Regions (with NERC oversight) should analyze the impacts to ERSs in order to maintain reliability. Additionally, system operators and ISO/RTOs need to develop appropriate processes, tools, and operating practices to adequately address operational changes on the system.

NERC should perform grid-level performance expectations developed from a technology-neutral perspective to ensure ERS targets are met.

The development of technologies (such as electricity storage) help support the reliability objectives of the BPS, and these technologies should be expedited to support the additional variability and uncertainty on the BPS.

Increased Penetration of Distributed Energy Resources (DERs)

ISO/RTOs and system planners and operators should consider the increasing penetration of DERs and potential reliability impacts due to the limited visibility and controllability of these resources.

Plan for NERC Reliability Assessments

After the proposed CPP is finalized, specific transmission and resource adequacy assessments—including resulting reliability impacts—will be essential for supporting the development of SIPs that are aligned with system reliability needs. NERC’s plan for reviewing and assessing the reliability impacts of the EPA proposal is included in Figure 1. This review includes a preliminary review of the assumptions and potential reliability impacts resulting from the implementation of the EPA’s proposed CPP. As the EPA is scheduled to finalize its rule by June 2015, NERC will develop a specific reliability assessment in early 2015 that will focus on evaluating generation and transmission adequacy and reliability impacts. After the EPA rule is finalized, the states, either individually or in multi-state groups, are required to develop their SIPs by 2016 and 2018, respectively. NERC plans to provide a more specific and comprehensive reliability assessment before SIPs are submitted to the EPA. Additionally, a Phase III approach is tentatively planned for December 2016, which will examine finalized SIPs.

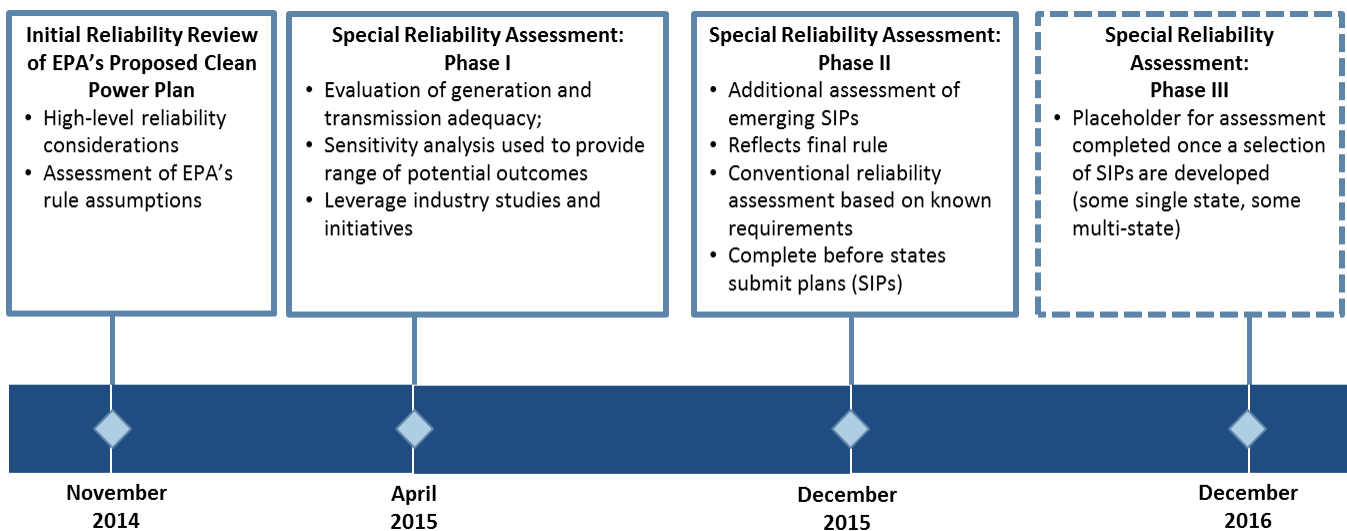


Figure 1. NERC’s Assessment Actions and Schedule Timeline

Summary of the Proposed Clean Power Plan

The proposed CPP aims to cut CO₂ emission from existing power plants to 30 percent below 2005 levels by 2030. Substantial CO₂ reductions are required under State Implementation Plans. Under the EPA proposal, CO₂ reductions are required as early as 2020. According to the EPA's reliability assessment included in the proposed rule, these existing generation rules would result in between 108 and 134 GW of generation retirements by 2020 (depending on state or regional implementations of Option 1 or 2).⁵

The CPP proposal would apply to fossil-fired generating units that meet four combined qualification criteria: (1) units that commenced construction prior to January 8, 2014;⁶ (2) units with design heat input of more than 250 MMBtu/hour (approximately a 25 MW unit); (3) units that supply over one-third of their potential output to the power grid; and (4) units that supply more than 219,000 MWh/year on a three-year rolling average to the power grid.⁷ Given these criteria, the EPA estimates that approximately 3,000 U.S. fossil-fired electric generation units representing over 700,000 MW of existing nameplate generating capacity will be subject to the rule limitations.⁸ NERC estimates that this magnitude represents approximately 65 percent of the total existing nameplate capacity in the United States.

The EPA-proposed draft regulations would, for the first time, limit CO₂ from existing power plants, thus addressing risks to health and the economy posed by climate change. These proposed regulations are intended to provide implementation flexibility and maintain an affordable, reliable energy system while cutting CO₂ and protecting public health and the environment.⁹

The EPA regulations propose implementation through a state-federal partnership under which states identify plans to meet the emission reduction goals. The EPA provides guidelines for states to develop implementation plans to meet state-specific CO₂ reduction goals and provides states the flexibility to design requirements suited to their unique situations. These plans may include generation mix changes using diverse fuels, energy efficiency, and demand-side management, and they allow states to work individually or to develop multi-state plans. The primary driver for realizing the EPA's 111(d) objectives is that SIPs need to produce significant CO₂ reductions starting as early as 2020.

As currently proposed, states have a flexible timeline for submitting plans to the EPA. Within one year of finalizing the rule—expected in June 2015—state environmental agencies must submit implementation plans to the EPA for approval. Submitted state-specific plans, due in June 2016, must outline requirements and enforceable limitations for affected generating units to meet the rule's average CO₂ emission rate goal for each state within two compliance periods: (1) an initial 10-year average interim emission rate limit for the period 2020–2029, and (2) a final annual emission rate limit starting in 2030.

The EPA provides states with an option to convert CO₂ emission rate limitation into an annual mass-based limitation. It is likely that most states will pursue this option due to the challenges state permitting agencies have in developing unit-specific emission rate limitations. The simpler mass-based CO₂ emission cap program also negates the need for state legislative action to authorize agencies to limit plant output and enact an enforceable program for compliance with average emission rates. The EPA's proposed Clean Power Plan timeline is outlined in Figure 2.

⁵ State implementation of Option 1 assumes 134 GW of retirements (includes CC, Coal, CT, Nuclear, O/G, and IGCC) by 2020. For additional information, see: Regulatory Impacts Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants (June 2014) and supporting [IPM Model](#) documentation and data. Regional implementation of Option 2 assumes 108 GW of retirements (includes CC, Coal, CT, Nuclear, O/G, and IGCC) by 2020.

⁶ All sources starting construction after January 8, 2014, would be subject to new source performance standards and exempt from the EPA Clean Power Plan requirements.

⁷ 79 FR 34854 <https://www.federalregister.gov/articles/2014/06/18/2014-13726/carbon-pollution-emission-guidelines-for-existing-stationary-sources-electric-utility-generating-page-34854>.

⁸ EPA CPP TSD – 2012 Unit-Level Data Using EGrid – Methodology, June 2014. Generation, Emissions, Capacity data used in EPA's State Goal Computation TSD.

⁹ EPA Fact Sheet: Clean Power Plan – Why we Need A Cleaner, More Efficient Power Sector “*The proposed Clean Power Plan will cut hundreds of millions of tons of carbon pollution and hundreds of thousands of tons of harmful particle pollution, sulfur dioxide and nitrogen oxides. Together these reductions will provide important health protections to the most vulnerable, such as children and older Americans.*” <http://www2.epa.gov/sites/production/files/2014-05/documents/20140602fs-benefits.pdf>.

Summary of the Proposed Clean Power Plan

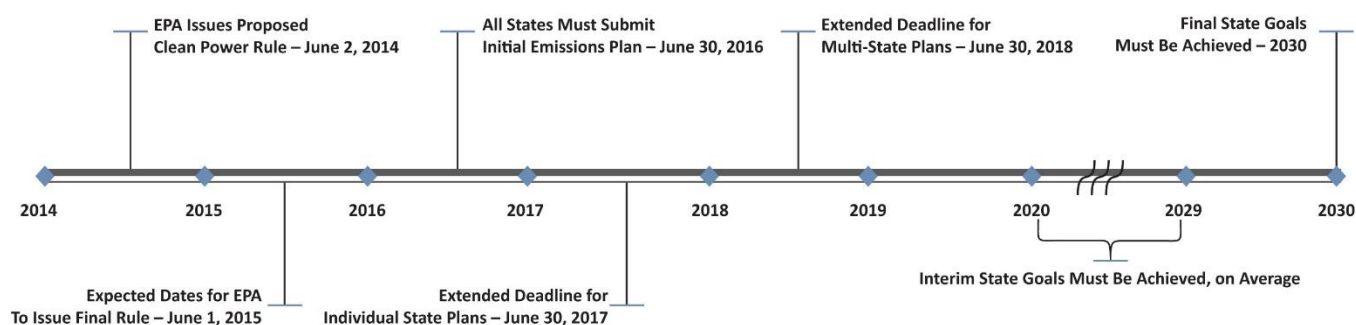


Figure 2. EPA Proposed Clean Power Plan Timeline

The EPA would have one year to review and approve implementation plans for each state by June 2017. Under this schedule, impacted generating units would have two and a half years to develop respective compliance strategies and potentially permit, finance, and build needed replacement capacity and transmission. In its current form, this implementation schedule would be a challenge for states to implement and for affected sources to comply with, especially given the expected legal challenges to both the EPA and state rules. In recognition of these challenges, the EPA would provide states with a one-year extension to June 2017 to submit a SIP if justification is provided, and a two-year extension (June 2018) for states that elect to develop multi-state (regional) programs (e.g., Regional Greenhouse Gas Initiative (RGGI)). While the EPA extensions apply to state plan submissions, the January 1, 2020, program start date for affected sources would not be extended under the proposed CPP. Therefore, the impacted fossil-fired units may be left with as little as six months to develop and implement compliance plans. Considering the number and variety of outcomes for each of the proposed scenarios, the states and industry should initiate planning immediately upon finalization of the CPP.

The proposed Clean Power Plan, which is based on EPA analysis of historical data about emissions and the power sector, is intended to create a consistent national formula for reductions that reflects their Building Block assumptions. The formula applies the four Building Blocks to each state’s specific information, yielding a carbon intensity rate for each state.¹⁰ There is a wide range of

potential proposals, including individual state and multi-state groupings, each with different implementation schedules. The range of potential submitted SIPs and changes to the proposed timeline create significant uncertainties for industry and resource planners.

Clean Power Plan Building Blocks

According to the proposed plan, this can be achieved through the development of state-specific emission rates to limit CO₂ by applying four different BSER Building Blocks.¹¹ Each Building Block represents a different approach for achieving the proposed targets. According to the EPA, the proposed plan considers impacts to system reliability and electricity prices. The BSER is not intended to impact resource planning and does not dictate retirements, additions, or operating practices for individual units. Instead, it would provide state emission rate limits that would shape the future resource mix through state and market processes in subsequent years as SIPs and multi-state plans are developed and implemented.

EPA’s Proposed Clean Power Plan: Options

The EPA is proposing a Best System of Emission Reduction (BSER) goal, referred to as Option 1, and is taking comment on a second approach, referred to as Option 2.

Option 1: Involves higher deployment of emission reduction but allows a longer time frame (2030).

Option 2: Has a lower deployment of emission reductions over a shorter time frame (2025) by each state. Proposed guidelines allow states to collaborate and demonstrate emission performance on a multi-state basis, in recognition that electricity is transmitted across state lines.

¹⁰ [EPA Fact Sheet: Clean Power Plan - National Framework for States.](#)

¹¹ EPA Clean Air Act: Section 111(d) authorizes EPA to apply “best system of emission reduction” to this section’s affected sources.

The EPA's Proposed Clean Power Plan: Four Building Blocks

Plant Efficiency

Make fossil fuel power plants more efficient by implementing a 6 percent (on average) unit heat rate improvement for all affected coal-fired units. The EPA suggests that some plants could further improve process efficiency by 4 percent through the adoption of best operational practices, and an additional 2 percent through capital upgrade investments.

Natural Gas

Use low-emitting power sources more by redispatching existing natural gas combined-cycle (NGCC) units before the coal and older oil-gas steam units. EPA draft rate limitations include CO₂ reduction assumptions from the ongoing increases in the use of NGCC capacity (with up to a 70 percent capacity factor). This additional NGCC capacity (440 TWh/year) displaces coal (376 TWh/year) and oil-gas steam generation (64 TWh/year) by 2020, compared to 2012 levels.

Renewable Energy

Use more zero- and low-emitting power sources through building capacity by adding both non-hydro renewable generation and five planned nuclear units. EPA calculations assume qualifying non-hydro renewable generation can grow rapidly from 218 TWh/year in 2012, to 281 TWh/year by 2020, to reach 523 TWh/year by 2030.

Energy Efficiency

Use electricity more efficiently by significantly expanding state-driven energy efficiency programs to improve annual electricity savings by up to 1.5 percent of retail sales per year. The calculation assumes the states and industry can rapidly expand energy efficiency programs to increase savings from 22 TWh/year in 2012, to 108 TWh/year in 2020, and to 380 TWh/year by 2029. Ultimately, EPA energy efficiency assumptions suggest that electric power savings will outpace electricity demand growth, resulting in negative electricity usage from 2020 through 2030.

Clean Power Plan – Assumption Review

This section provides a critical review of the EPA’s assumptions for state-specific CO₂ emission rates and presents possible reliability challenges that need to be considered.

Building Block 1 – Coal Unit Heat Rate Improvement

Plant Efficiency

The EPA’s heat rate assessment analyzed gross data for 884 coal-fired electric generating units (EGUs) during a 10-year period.¹² The regression analysis examined the effects of the capacity factor and the ambient temperature on the gross heat rate efficiencies of coal-fired EGUs. The EPA’s assessment concluded that in-state coal units can achieve up to a 4 percent rate of improvement through the use of best operational practices. An additional 2 percent of efficiency improvements would be achieved through capital upgrade investments.

Review of EPA Assumptions and Potential Reliability Impacts

The EPA calculated unit-specific heat rates using gross generation data from the Continuous Emission Monitoring Systems (CEMSs). With this approach, the EPA excluded generation-reducing effects from post-combustion environmental controls, such as selective catalytic reduction and flue-gas desulfurization controls. The EPA then used net generation data, without consideration for these retrofits, for coal-fired EGUs when calculating the state CO₂ emission rate goals. These retrofits will reduce the net output of these units, as well as their associated net heat rate efficiency. Not considering these reductions creates an inconsistent approach, especially considering that most coal-fired EGUs will require control retrofits to comply with environmental regulations, such as the Mercury Air Toxic Standards (MATS) and Section 316(b) of the Clean Water Act.

The EPA’s regression analysis does not adjust for the following factors that have profound effects on the process efficiency of a coal-fired EGU:¹³ (1) subcritical versus supercritical boiler designs; (2) fluidized bed combustion, integrated gasification combined-cycle (IGCC), and pulverized coal; (3) unit size and age; and (4) coal quality variations in moisture and ash (i.e., every 5 percent change in coal moisture results in a 1 percent change in boiler heat rate efficiency).

Impacts on Coal-Fired Unit Efficiency Rates

Lower-capacity factors will cause an increase in heat rates, particularly if the lower-capacity factors are due to the cycling of the coal units. As a result of Building Block 2, coal units will cycle more often; therefore, assumed heat rate improvements across the entire coal fleet are unlikely. While recognizing capacity effects in the regression analysis, the EPA did not evaluate the effects of lower-capacity factors resulting from the dispatching of natural gas generation before coal generation.

Periodic Turbine Overhauls

Turbine overhauls are referenced as a major heat rate improvement method in an EPA Clean Power Plan technical support document.¹⁴ Regular turbine overhauls are generally not practical or economical, because these procedures require the unit to be out of service for an extended period of time. As well, the power industry already has multiple incentives to operate units at peak efficiency (i.e., profit maximization and competitive advantage).

Overall, improving the existing U.S. coal fleet’s average heat rate by 6 percent may be difficult to achieve. Possible options and considerations for attaining a portion of this target may include the following:

- Site-specific engineering analyses are required to determine if there are remaining opportunities for heat rate improvement measures through implementation of operational best practices or capital investments.
- If the U.S. coal fleet does not achieve target heat rates, more CO₂ reductions would be required from other CPP Building Block measures.
- This can result in some coal-fired power plants retiring earlier than anticipated, which creates additional uncertainty in future generation resources.

¹² *GHG Abatement Measures* (EPA June 2014) (EPA-HQ-OAR-2013-0602) pg. 2-18.

¹³ These differences are illustrated in Figure 2-2 of *GHG Abatement Measures* (EPA June 2014).

¹⁴ [Coal-Fired Power Plant Heat Rate Reductions](#) (January 2009).

Building Block 2 – Gas Unit Re-Dispatching

Natural Gas

The EPA assumes that reductions in CO₂ emissions from existing power plants can be achieved by dispatching existing NGCC units ahead of coal units. In particular, the EPA assumes existing NGCC units can achieve a 70 percent utilization rate with avoided incremental costs of less than \$33/metric ton CO₂.¹⁵ In its state-specific goal computation, the EPA calculated that 440 TWh/year of additional NGCC generation could potentially displace 376 TWh/year of coal and 64 TWh/year of oil-gas steam units of 2012 generation.¹⁶

Review of EPA Assumptions and Potential Reliability Impacts

Upon reviewing the EPA’s Building Block 2 assumptions, NERC found a number of reliability concerns regarding increased reliance on natural-gas-fired generation that should be evaluated.

Historically, the primary function of the NGCC unit is to follow the load of energy throughout the day (i.e., the intermediate, or midrange, part of the load duration curve). While some NGCC units are capable of operating at a high capacity factor, the vast majority of this type of generation is used for load following. Due to lower gas prices, NGCC units are currently being dispatched as a baseload resource, displacing baseload coal-fired EGUs. Unlike baseload coal-fired generation, NGCC units are better suited to follow load. As mentioned earlier, cycling coal-fired EGUs reduces heat rate efficiencies, causing their CO₂ emission rates (lbs/MWh) to deteriorate, and further offsetting the Building Block 1 assumptions.

Generally, the power industry relies upon diversification of fuel sources as a mechanism to offset unforeseen events (e.g., abnormal weather, regional transfers, labor strikes, unplanned outages); ensure reliability; and minimize cost impacts. Fuel diversification is also a component of an “all-hazards” approach to system planning, which inherently provides resilience to the BPS. The EPA estimates that an additional 49 GW of nameplate coal capacity will retire by 2020 due to the impacts of the proposed CPP.¹⁷ When including the 54 GW of nameplate coal capacity already announced to retire by 2020¹⁸ (mostly due to MATS), the power industry will need to replace a total of 103 GW of retired coal resources by 2020, largely anticipated to be natural-gas-fired NGCC and CTs. Considering the current and ongoing shift in the resource mix, the EPA proposes to further accelerate the shift, lessening the industry’s diversification of fuel sources.

As observed during the 2014 polar vortex,¹⁹ the relationship between gas-fired generation availability and low temperatures challenges the industry’s ability to manage extreme weather conditions—particularly when conditions affect a wide area and less support is available from the interconnection. The polar vortex served as an example of how extended periods of cold temperatures had direct impacts on fuel availability, especially for natural-gas-fired capacity. Higher-than-expected forced outages were observed during the polar vortex, particularly for natural-gas-fired generators, as a result of fuel delivery issues and low temperatures. Overall, extreme weather conditions have the potential to strain BPS reliability and expose risks related to natural-gas-fired generation availability (Figure 3). With greater reliance on natural-gas-fired generation, the resiliency and fuel diversification that is currently built into the system may be degraded, which NERC has highlighted in recent gas-electric interdependency assessments.

¹⁵ *GHG Abatement Measures* (EPA June 2014) (EPA-HQ-OAR-2013-0602) pg. 3-26.

¹⁶ Clean Power Plan Proposed Rule: Goal Computation – Technical Support Document <http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-goal-computation>.

¹⁷ *Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants* (EPA June 2014 pg. 3-32).

¹⁸ Energy Ventures Analysis maintains a complete list of announced power plant retirements in the contiguous United States, retirements as of 10/02/2014.

¹⁹ NERC 2014 Polar Vortex Review:

http://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf

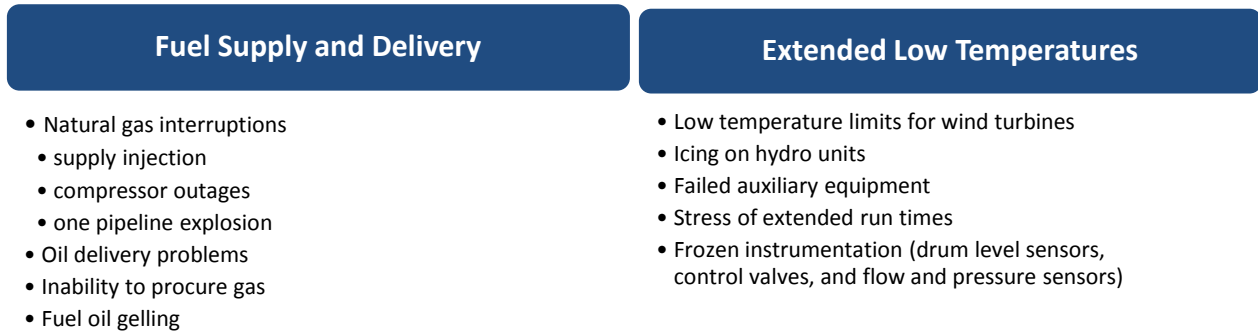


Figure 3. Causes for Generator Outages Observed during the 2014 Polar Vortex

Pipeline Capacity Constraints

During its assessment of Building Block 2, the EPA concludes that the power industry in aggregate can support higher gas consumption without the need for any major investments in pipeline infrastructure. However, there are a few critical areas that likely will need additional capital investments. As an example, current and planned pipeline infrastructures in Arizona and Nevada are inadequate for handling increased natural gas demand due to the CPP. Pipeline capacity in New England is currently constrained, and more pipeline capacity additions will be needed as more baseload coal units retire—this is generally occurring as projected and independent of the CPP. Timing of these investments is also critical as it takes three to five years to plan, permit, sign contract capacity, finance, and build additional pipeline capacity, in addition to placing replacement capacity (e.g., NGCC/CT units) in service. The proposed CPP timelines would provide little time to add required pipeline or related resource capacity by 2020.

Due to abundant availability of natural gas, the power industry is generally able to accommodate increased demand from NGCC plants that operate as baseload capacity. This higher dependence on natural gas can expose additional reliability risks, including pipeline transportation constraints that could result as more gas-fired generation is built. Overall, the increase in natural gas use and capacity expansion increases gas-electric interdependency issues and raises the following concerns:

- NGCC units could displace coal-fired generating units as baseload units, forcing less-efficient coal units out of service, further increasing demand for natural gas.
- Adequate timing is required to add new pipeline and generation resource capacity where it is needed to offset coal plant retirements and supply natural gas to new generation.
- As gas-electric dependency significantly increases, unforeseen events like the 2014 polar vortex could disrupt natural gas supply and delivery for the power sector in high-congestion regions, increasing the risk for potential blackouts.

Building Block 3 – Clean Energy

Renewable Energy

Building Block 3 describes the EPA’s method to reduce CO₂ emissions by investing in zero-CO₂-emitting energy sources (i.e., nuclear and non-hydro renewable generation).

Review of EPA Assumptions and Potential Reliability Impacts

Building Block 3 includes the assumption about the preservation of nuclear generating units that are currently at risk of being retired within the next two decades due to (1) age, (2) an increase in fixed operation and maintenance costs, (3) relatively low wholesale electricity prices, and (4) additional capital investment associated with ensuring plant security and emergency preparedness. The EPA assumes that 5.7 percent of each state’s nuclear generating capacity is at risk of retirement. However, the EPA included this generation as well as the five new nuclear units currently under construction (Watts Bar Unit 2 (TN), Summer Units 2-3 (SC), and Vogtle Units 3-4 (GA)) in its state-by-state CO₂ emission rate goal calculations.²⁰ The nuclear retirement assumptions add pressure to states that will need to retire nuclear units. For these states, more CO₂ reductions from other measures than originally estimated by the EPA may be required.

Under its draft CPP, the EPA also proposes significant expansion of non-hydro renewable generation as part of its BSER determination. The EPA adopted a methodology to estimate non-hydro renewable generation by state and year and applied these estimates in their calculation of individual state emission rate limitations. The greater the EPA’s assumed non-hydro renewable generation in a given state, the lower the state’s calculated CO₂ emission rate limit.

The EPA assumes that qualifying non-hydro renewable generation will grow from 213 TWh/year in 2012, to 281 TWh/year by 2020, reaching 523 TWh/year by 2030. These projections exceed the Energy Information Administration (EIA) non-hydro renewable generation forecast in their Annual Energy Outlook 2013 (AEO 2013) that grows from 202 TWh/year in 2012, to 275 TWh/year by 2020, to reach 317 TWh/year by 2030 for all sectors.²¹ The EPA-assumed rapid growth in non-hydro renewable generation exceeds its own forecast in the EPA’s *Regulatory Impacts Assessment* (356 TWh/year by 2030).²²

To calculate the state target levels of renewable energy performance, the EPA examined mandatory state Renewable Portfolio Standard (RPS) requirements from the Database for State Incentives for Renewables and Efficiency (DSIRE).²³ RPS requirements vary widely by state; many states include resource-specific percentage requirements (i.e., set-asides) that promote development of certain resources in addition to their general requirements. The database distinguishes the complex web of state policies by applying them to a standardized tier system which, according to DSIRE, helps “to compare RPS policies on equal footing.”²⁴ To determine the state effective levels in 2020, the EPA added each state’s tiers together and excluded secondary and tertiary tiers that include energy efficiency or qualified fossil fuels (waste coal, carbon capture sequestration, etc.). The only RPS “type” considered was the primary type, referring to requirements for investor-owned utilities (IOUs).

Significant regional differences exist in the availability of renewable resources and their power production costs across the United States. In order to quantify these regional differences, the EPA divided the lower 48 states into six regions, based on designations by NERC Regions and ISO/RTOs. After the regions were assigned, the EPA averaged the 2020 effective levels for states that have mandatory RPS percentage standards. By applying the average regional renewable energy (RE) percentages to each region’s aggregate 2012 generation, the EPA derived a new RE target generation level for 2030. The EPA notes that Alaska and Hawaii were assigned RE generation target percentages equal to the lowest value of the six regions, equivalent to the Southeast’s target. The EPA assumes that RE generation will begin increasing in 2017 and continue through 2029. Moreover, they assume no growth occurs in between 2012 and 2016. The EPA derived the annual growth factor by determining “the amount of additional renewable generation (in megawatt-hours) that would be required beyond each

²⁰ *GHG Abatement Measures* (EPA June 2014) (EPA-HQ-OAR-2013-0602) pg. 4-33.

²¹ *Annual Energy Outlook 2013* (EIA April 2013) reference case data.

²² *Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants* (EPA June 2014) Table 3-11 pg. 3-27.

²³ <http://www.dsireusa.org/>.

²⁴ DSIRE. DSIRE RPS Field Definitions. April 2011. <http://www.dsireusa.org/rpsdata/RPSFieldDefinitionsApril2011.pdf> p.1.

region's historic (2012) generation to reach that region's RE target²⁵ by 2030. This constant growth rate is then applied to each state to obtain annual state RE target levels.

The EPA's reliance on state RPS standards to compute the regional performance targets poses a variety of issues. States' main-tier RPS qualifications vary significantly and, in addition to in-state non-hydro renewable generation, also often include: hydroelectric generation, municipal solid waste (MSW), combined heat and power (CHP), clean coal, carbon capture and sequestration, and energy efficiency measures. As an example, New York has an RPS percentage of 30 percent.²⁶ According to the *New York Renewable Portfolio Standard Cost Study Report* produced by the New York State Department of Public Service, hydroelectricity contributes 18.25 percent of total generation and is included under baseline renewables.²⁷ New York's RPS percentages, therefore, include the state's hydroelectric generation as qualifying renewable resources, which is different from what the EPA assumed in its methodology.

In addition to hydroelectric power, energy efficiency plays an important role in various states' RPSs. North Carolina's RPS includes a provision that allows up to 25 percent of its target to be met by energy efficiency gains. This provision, if it were properly excluded by the EPA, would reduce North Carolina's RPS target to 7.5 percent from 10 percent, thereby lowering targets for the entire Southeast region, Alaska, and Hawaii. When establishing 2012 non-hydro renewable generation performance levels, the EPA excluded all hydroelectric generation and energy efficiency programs used in the state CO₂ emission rate calculations. The adjusted state RPS targets, as well as 2012 non-hydro RE performance levels, are used to determine the regional RE targets and regional annual growth rates.

NERC notes several other concerns with the CPP's assumption for Building Block 3, such as:

- Multipliers given to select resources' options (e.g., in-state, wind, solar, etc.). Six states (CO, DE, MI, NV, OR, and WA) give extra credit (up to 3.5 renewable energy credits per 1 MWh of energy produced) for using these resources.²⁸ Excluding the multiplier suggests a target that is ultimately higher than what may actually be attainable.
- The use of qualifying out-of-state renewable generation resources in effective RPS target calculations. Most RPS programs allow out-of-state qualifying renewable resources toward RPS compliance. For example, several Indiana wind projects account for nearly 50 percent of the Ohio RPS requirement. This issue is important since states realize that much of the lower-cost renewable resources may come from outside the state in locations more suitable for VERs. The underlying assumption—that the state RPS reflects in-state renewable capability that can be matched by the other states in their census region—appears incorrect and could only be dealt with via a regional state approach similar to a regional greenhouse gas initiative. In order to properly account for regional renewable resource potential, the EPA should consider including only in-state renewable resource portions of the state RPSs.
- The EPA method of assigning renewable regions is questionable. Of the six renewable regions created in the lower 48 states, targets for two regions (South Central and Southeast) were set based upon a single-state RPS. For example, the South Central state region (AR, KS, LA, NE, OK and TX) was set based upon only the Kansas RPS. Kansas accounts for only 6 percent of this region's retail power sales and has the third-best wind resources in the country. Given the combination of a low population, large land area, and very high wind resource availability, Kansas has relatively low costs to meet its RPS. However, Louisiana (ranked #48 in wind resources and double the retail sales) is assigned the same non-hydro renewable target. To put these two states in the same region sets unattainable targets for Louisiana.
- The EPA's determination of state goals for renewable generation does not fully reflect the economic aspects of renewable resources. Resource limitations exist due to permitting, market saturation, transmission access, and project financing issues. Many prime wind locations have difficulty obtaining the necessary permits and are often objected to at the local level. Many high-grade wind sites are also located in remote areas. Energy generated from

²⁵ *GHG Abatement Measures* (EPA June 2014) (EPA-HQ-OAR-2013-0602) pg. 4-18.

²⁶ http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=NY03R&re=0&ee=0.

²⁷ <http://www.dps.ny.gov/rps/Appendix-B-2-19-04.pdf>.

²⁸ DSIRE <http://www.dsireusa.org/>.

these locations requires large capital investments to build transmission infrastructure to interconnect to the BPS. Location matters, and sites with high capacity factors are limited.

- The expiration of the production tax credits (PTCs) and potential reduction of the investment tax credits (ITCs) for RE resources in the coming years will impact investment decisions and the economics of new resources. As a result, the marginal cost of new RE generation increases, which could impact the long-term development of RE resources. There is also the implicit need to increase ancillary services as a result of the increased variable resource output. Moreover, there are higher production costs associated with more non-hydro renewable generation due to a combination of increased capital costs and low-capacity operating factors. Overall, significant cost uncertainties will directly impact the electric industry's plan to quickly adapt to the CPP requirements.

Finally, grid reliability issues associated with increased variable resources are not directly addressed in the EPA's proposed Building Blocks. Conventional generation (e.g., steam and hydro), with large rotating mass, has inherent operating characteristics, or ERSs,²⁹ needed to reliably operate the BPS. These services include providing frequency and voltage support, operating reserves, ramping capability, and disturbance performance. Conventional generators are able to respond automatically to frequency changes and historically have provided most of the power system's essential support services. As variable resources increase, system planners must ensure the future generation and transmission system can maintain essential services that are needed for reliability.

A large penetration of VERs will also require maintaining a sufficient amount of reactive support and ramping capability. More frequent ramping needed to provide this capability could increase cycling on conventional generation. This could contribute to increased maintenance hours or higher forced outage rates, potentially increasing operating reserve requirements. While storage technologies may help support ramping needs, successful large-scale storage solutions have not yet been commercialized. Nevertheless, storage technologies support the reliability challenges that may be experienced when there is a large penetration of VERs, and their development should be expedited.

Based on industry studies and prior NERC assessments,³⁰ as the penetration of variable generation increases, maintaining system reliability can become more challenging. Additional assessments, including interconnection-wide studies, will be needed as the resource plans unfold to better understand the impacts.

If the states fall short of meeting the renewable energy targets established by the EPA, more CO₂ reductions from other measures may be required than were estimated by the EPA. These measures include more coal unit retirements, expanded natural gas-fired generation plants, or energy efficiency deployment.

The CPP proposes reductions in CO₂ emissions by investing in zero-CO₂-emitting energy sources (i.e., nuclear and non-hydro renewable generation). However, increased reliance on VERs creates reliability challenges that take considerable time to implement and require substantial changes in BPS planning and operations. Most notably, the challenges with this Building Block are:

- The CPP analysis relies on resource projections that may overestimate reasonably achievable expansion levels and exceed NERC and industry plans and do not fully reflect the reliability consequences of renewable resources.
- Increased reliance on VERs can significantly impact reliability operations and requires more transmission and adequate ERSs to maintain reliability.
- With a greater reliance on VERs, transmission and related infrastructure expansion lead times may not align with the CPP implementation timeline.

²⁹ See NERC's Essential Reliability Services Task Force website for more information:

[http://www.nerc.com/comm/Other/Pages/Essential-Reliability-Services-Task-Force-\(ERSTF\).aspx](http://www.nerc.com/comm/Other/Pages/Essential-Reliability-Services-Task-Force-(ERSTF).aspx).

³⁰ NERC-CAISO Joint Report: [Maintaining Bulk Power System Reliability While Integrating Variable Energy Resources – CAISO Approach](#); other industry reports include those developed by the [Integration of Variable Generation Task Force \(IVGTF\)](#); [Integrating Variable Renewable Energy in Electric Power Markets: Best Practices from International Experience \(Appendix D\)](#).

Building Block 4 – Energy Efficiency

Energy Efficiency

Electricity savings from enhanced energy efficiency measures are assumed as a major reduction in U.S. power generation requirements and thereby lower U.S. power industry CO₂ emissions. In calculating individual state CO₂ emission rate limits, the EPA assumes that existing state energy efficiency programs can be significantly expanded to achieve 108 TWh in cumulative savings in 2020, continue to grow to 283 TWh by 2025, and reach 380 TWh by 2030.³¹ The EPA's estimated future energy efficiency program performance will have significant effects on state compliance measures and costs.

Review of EPA Assumptions and Potential Reliability Impacts

In its *Regulatory Impact Assessment*, the EPA assumes that energy efficiency will grow faster than electricity demand, with total electricity demand shrinking beyond 2020. The implications of this assumption are complex. If such energy efficiency growth cannot be attained, more carbon reduction measures would be required, primarily from reduced coal generation in most states. More low-emitting or new NGCC/CT generating capacity (not regulated under the CPP) would need to be built. Construction of new replacement capacity, as well as related infrastructure, would take time to plan, permit, finance, and build. If these needs are not identified at an early enough stage, either grid reliability or state CO₂ emission goals could be compromised.

The EPA relied on 12 state studies to set its expanded annual program target savings improvement rate at 1.5 percent per year. However, the EPA appears to overestimate most states' energy efficiency savings potential versus prior energy efficiency projections, resulting in setting performance targets too high for individual states.³² Savings potentials are highly state specific in their consumer mix, credit for measures already taken, and levels of subsidies provided. The EPA applies one national energy efficiency growth factor to all state situations and does not consider energy efficiency program performance or cost. The discrepancies are subsequently compounded by extrapolating these annual energy efficiency performance targets as incremental improvements that can be sustained through 2030—beyond the 12 studies evaluated.

Out of 12 studies, 11 contain multiple scenarios with different sets of assumptions to demonstrate wide ranges of what is achievable under alternative financial, technological, and behavioral environments. There is no documentation on how each study's respective average annual improvement rate was calculated, which was used as the foundation to calculate the incremental performance improvement target of 1.5 percent per year.

The assumed base year is of critical importance when comparing multiple studies' achievable potential for energy efficiency. When drawing comparisons between percentages, the baseline level of electricity demand must be the same; otherwise, the total amount of energy avoided due to energy efficiency measures would be different. Under the CPP, all energy efficiency savings are applied to Business As Usual (BAU) sales forecasts generated from EIA-861 data.³³ Base years used in the 12 studies range from as early as 2007 to as recently as 2013 and are not consistent throughout the sample.³⁴ Comparing achievable energy efficiency potential percentages is therefore difficult, since BAU electricity demand levels are inconsistent between the studies.

Study length is another important assumption regarding the sustainability of achievable savings. It is uncertain whether the level of annual energy efficiency savings could be sustained after the expiration of the program, as the most cost-effective and impactful measures would have been utilized already—leaving only increasingly expensive incremental energy efficiency measures. The cited studies vary significantly in length: from as few as four years, to as many as 21 years.

The CPP assumes that dividing cumulative potential by the study length provides an adequate estimation for an average annual achievable potential that is sustainable over a much longer (13-year) period (2017–2030). However, there is a discrepancy in the longitudinal application of cross-sectional studies.

³¹ EE savings estimates calculated using EPA's methodology, EE savings %, BAU sales estimates. Source: *GHG Abatement Measures* (EPA June 2014) (EPA-HQ-OAR-2013-0602) Chapter 5.

³² Electric Power Research Institute (EPRI) and EIA.

³³ *Annual Electric Power Industry Report* (EIA 2012) (EIA 861 Data).

³⁴ *GHG Abatement Measures* (EPA June 2014) (EPA-HQ-OAR-2013-0602) pg. 5-65.

The CPP assumes an average life of 10 years for energy efficiency measures. This average does not fully capture the unique distribution of the length of measures when analyzing regionally available energy efficiency measures. Key assumptions when determining energy efficiency potential are “breadth of sectors and end uses considered, study period, discount rate, pattern of technology penetration, whether economically justified early replacement of technologies is allowed for, whether continued improvement in efficiency technology is provided for,”³⁵ yet the EPA applies a broad average rather than determining individual measure life curves. Most of the source studies perform bottom-up approaches and evaluate thousands of permutations of measures, building types, climate zones, market penetration factors, and measure lives to determine which energy efficiency technologies to include and exclude. By approximating thousands of measure lives using one average, the CPP does not capture measure life disparities and possibly underestimates the amount of energy efficiency savings that expire throughout the compliance period.

While the studies on energy efficiency consider different potentials for the three main sectors (residential, commercial, and industrial), the CPP uses one number across all sectors in its emission rate calculation. Industrial processes are designed to use as little energy as possible in order to maximize profits of daily operations and may have already invested in energy efficiency programs, leaving minimal and costly opportunities remaining for incremental improvement. Applying the same energy efficiency potential percentage for all three sectors indirectly provides incentives for industrial utility customers to reduce their energy load proportional to residential customers, but by a much greater magnitude per capita.

The underlying state and regional studies used as the base for calculating the 1.5 percent potential include the full range of financial incentives from 25 to 100 percent, when considering base, low, and high cases. Since the EPA uses an averaging method in translating from the observed studies’ sector and scenario findings to the final average annual projected potential, it is difficult to evaluate the financial incentives that are assumed in both the Building Block calculations and study results.

The EPA used the EIA’s AEO 2013 baseline forecast to estimate its BAU electricity sales forecast. Growth rates calculated by the National Energy Modeling System (NEMS) region were applied to state-level 2012 retail sales from the EIA-861 survey to arrive at an annual BAU sales forecast. These growth figures include the net effect of implicit forms of energy efficiency, as that information is not explicitly presented in AEO 2013 reference case. Because the EIA does not explicitly model energy efficiency as a forecast line item, the retail sales growth is skewed for the purposes of calculating the energy efficiency Building Block.

The EIA presents some metrics to gauge energy efficiency in the AEO 2013 model results. Energy intensity, defined as energy use per dollar of GDP, represents the aggregate effects of energy consumption trends and a rising national output. Electricity energy intensity, in particular, has been on a steady decline in both consumption per dollar of GDP and consumption per capita. This is due in large part to energy efficiency, but its contribution is difficult to isolate. The EIA’s AEO 2013 energy load growth projections include implicit forms of energy efficiency measures, and the proposed CPP does not appear to account for these savings. This effectively double counts the savings of some energy efficiency measures and results in state-specific energy efficiency targets that are too high to be considered reasonably achievable.

With potentially overstated expectations for energy efficiency savings, the EPA’s demand forecast results in a decline in electricity use between 2020 and 2030. While other major power market forecasters’ electricity sales compounded annual growth rates (CAGRs) for the period between 2020 and 2030 are strictly positive (AEO 2013: 0.7 percent, EPRI: (achievable potential) 0.4 percent, NERC average of assessment studies: 1.5 percent), the EPA assumes a CAGR of -0.2 percent for the same time period. Between 2020 and 2030, the EPA assumes incremental year-over-year reductions from energy efficiency to be almost 41 TWh nationally on average, outpacing year-over-year national electricity sales growth of 31.6 TWh, on average.

The main reason for this result is the EPA’s assumption of states being able to sustain an annual incremental growth rate in energy efficiency savings of 1.5 percent once achieved. As mentioned above, this sustainability is not supported by any peer-reviewed or technical studies of energy efficiency potential.

³⁵ *GHG Abatement Measures* (EPA June 2014) (EPA-HQ-OAR-2013-0602) pg. 5-22.

By overestimating efficiency savings resulting in declining electricity retail sales, the results of the EPA’s entire *Regulatory Impact Assessment* are concerning from a reliability perspective and have implications to electric transmission and generation infrastructure. Underlying electricity demand forecasts directly influence the required level of generation—and hence, CO₂ emissions—from existing and affected generating units under the CPP. They also affect the required new construction of generating units that are needed to meet expected electricity demand, which is projected to increase during the next 10 years.³⁶

The EPA projection for energy efficiency growth at a 1.5 percent annual increase is substantially greater compared to what NERC examined in its current and prior long-term reliability assessments (LTRAs). NERC collects energy efficiency program data that is embedded in the load forecast for each LTRA assessment area. Projected annual energy efficiency growth as a portion of Total Internal Demand since 2011 has ranged from only 0.12 to 0.15 percent, as shown in the table below.

Table 1. 2011–2014 LTRA Energy Efficiency Growth

LTRA	10-Year Growth of EE (%)	Portion of Total Internal Demand (%)		Annual Growth in Relation to Total Internal Demand (%)
		Year 1	Year 10	
2011	10.7	0.59	1.63	0.12
2012	12.2	0.72	1.88	0.13
2013	11.6	0.92	2.02	0.12
2014	13.4	0.87	2.25	0.15

In summary, the CPP assumes energy efficiency gains outpace electricity demand growth through the compliance period. However, this assumption does not reasonably reflect energy efficiency achievability and is a departure from normalized forecasts. If states are unable to achieve the EPA target savings, additional CO₂ reduction measures beyond BSER measures would be needed to meet the proposed rate limits—primarily through further reductions in existing generation or expansion of natural gas and VERs. The energy efficiency assumptions underpin the CPP proposal and present the following reliability issues:

- The EPA appears to overestimate the amount of energy efficiency expected to reduce electricity demand over the compliance time frame. The results of overestimation have implications to electric transmission and generation infrastructure needs.
- Substantial increases in energy efficiency programs exceed recent trends and projections. Several sources, including but not limited to NERC, EIA, EPRI, and various utilities, have published reports, analysis, and forecasts for energy efficiency that do not align with the CPP’s assumed declining demand trend.
- The CPP assumption appears to underestimate costs and may underestimate the capital investments that would be required by utilities to sustain energy efficiency performance through 2030.
- The offsetting requirements in more coal retirements, along with expansions in natural gas and VERs, in a constrained time period could potentially result in reliability or ERS constraints.

³⁶ NERC 2014 Long-Term Reliability Assessment.

Reliability Impacts Potentially Resulting from the CPP

To meet the proposed CPP emission reduction levels, the states are expected to select the mass-based limitation approach over the emission rate approach due to its greater flexibility, as well as ease to enforce and implement. The power industry has been successful in complying with prior mass-based emission cap and trade programs (e.g., Acid Rain program, Clean Air Interstate Rule, and RGGI) without creating reliability impacts. The CPP introduces potential reliability concerns that are more impactful than prior environmental compliance programs due to the extensive impact to fossil-fired generation. Additionally, there is potential for an accelerated decision-making period for the implementation of the CPP’s Building Blocks. It is also important to consider the ongoing transformation to the resource mix and corresponding impacts on ERSs required to maintain a reliable BPS. State-specific carbon intensity targets create potential reliability concerns in two major areas: (1) direct impacts to resource adequacy and electric infrastructure, and (2) impacts resulting from the changing resource mix that occur as a result of replacing retiring generation, accommodating operating characteristics of new generation, integrating new technologies, and imposing greater uncertainty in demand forecasts.

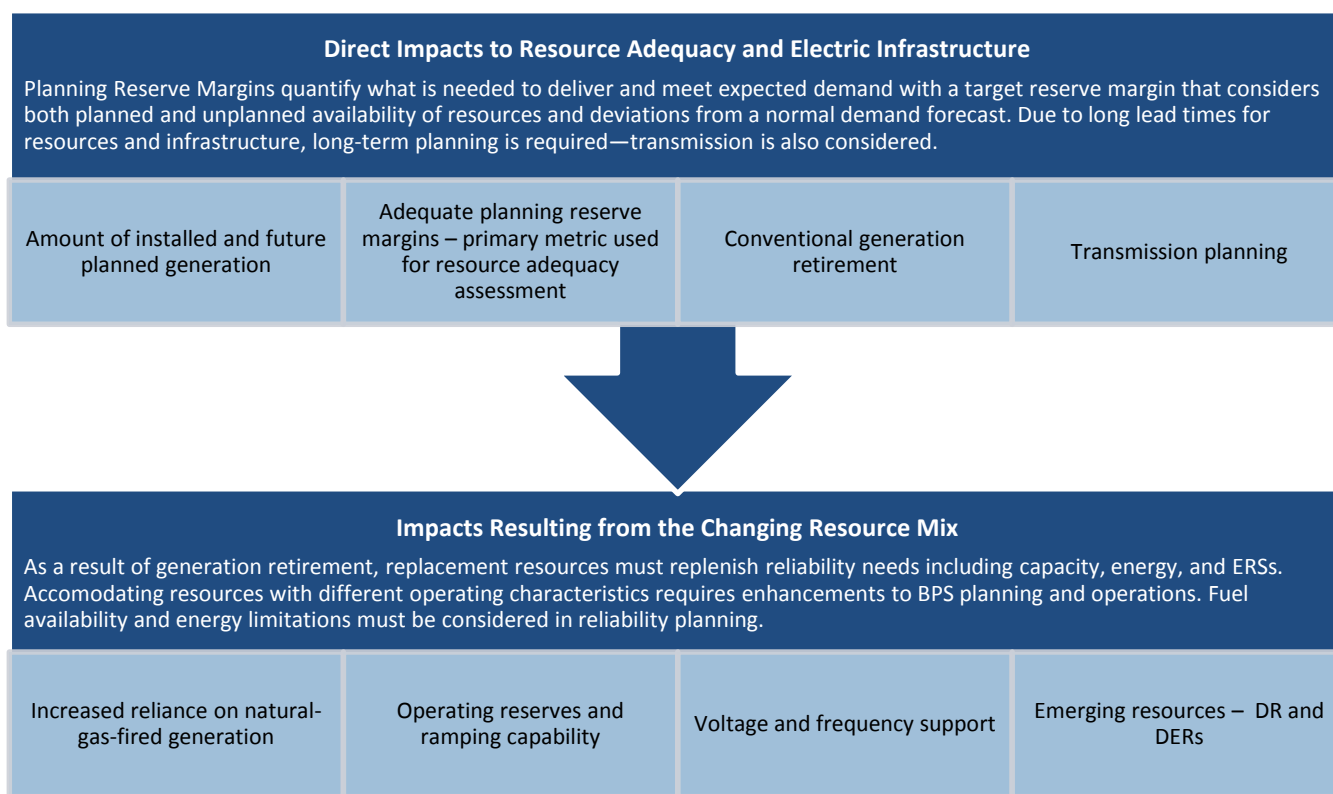


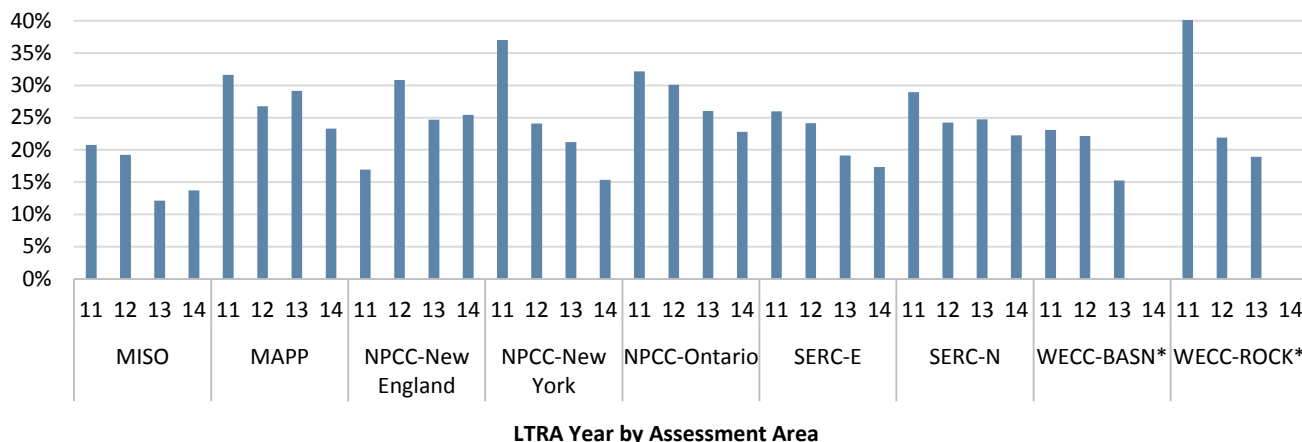
Figure 4. Summarized Reliability Challenges

Most importantly, generation (along with other system resources) and transmission must provide specific capabilities to ensure the BPS can operate securely under a myriad of potential operating conditions and contingencies, in compliance with a wide range of NERC planning and operating Reliability Standards. The above challenges warrant further consideration by policy makers. The following sections discuss these key reliability challenges in detail.

Direct Impacts to Resource Adequacy and Electric Infrastructure Fossil-Fired Retirements Result in Accelerated Declines of Reserve Margins

In recent long-term assessments, NERC has highlighted resource adequacy concerns, particularly in ERCOT, NPCC-New York, and MISO, as projections continue to reflect declining reserve margins that fall below each area’s Reference Margin Level over the next five years, despite low demand growth rate (Figure 5). As most LTRA assessment areas attribute stagnant demand growth to the ongoing projected economic indicators (typically based on either employment levels or GDP) in the

residential, commercial, and industrial sectors, total capacity additions have paralleled the ongoing declines in load growth. The trend of declining margins in a number of NERC assessment areas is rooted primarily from a general reduction in 10-year capacity additions observed over the past several years. Total capacity additions continue to fall behind the ongoing declines in load growth rates (Figure 6).³⁷



*Due to changes to the WECC subregional boundaries, resulting in four subregions instead of nine, the 2014 Anticipated Reserve Margins are not shown for WECC-BASN and WECC-ROCK for this comparison.

Figure 5. Short-Term (Year 2 Forecast) Anticipated Reserve Margins Show Declining Trends for Some Assessment Areas

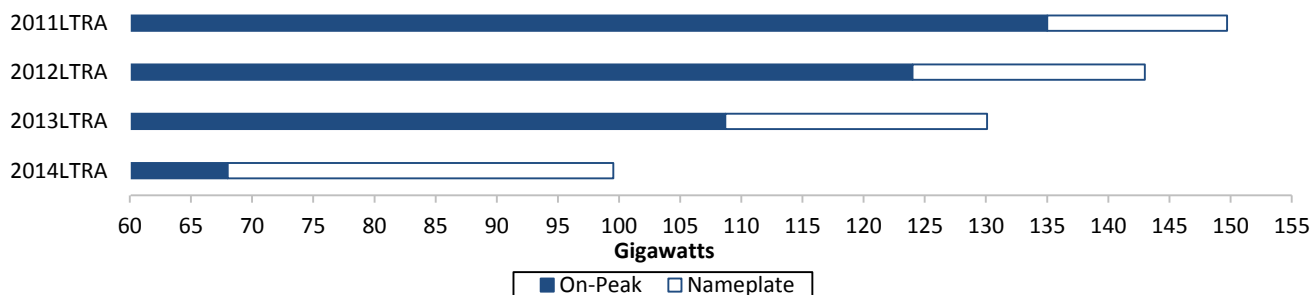


Figure 6. NERC-Wide 10-Year Projected Capacity Additions Declining Since 2011

The EPA’s supporting documents estimate that up to 19 percent of the nation’s coal plants will become “uneconomical” as a result of the proposed CPP. Although the CPP may not become enforceable until 2020, its effect may overshadow and change large retrofit capital decisions needed to comply with earlier EPA regulations—primarily MATS.

According to the EPA, the state implementation would result in a reduction in coal to 193 GW by 2025. The EPA finalized MATS, which is factored into 2014 LTRA and identifies capacity retirements through 2016. In its *Technical Support Document – Resource Adequacy and Reliability Analysis*, the EPA used the Integrated Planning Model (IPM) to project likely future electricity market conditions with and without the proposed CPP. The IPM assumed that adequate transmission capacity exists to deliver any resources located in, or transferred to, the individual regions. Additionally, since most regions currently have capacity above their target reserve margins, the EPA assumed most of the retirements are absorbed by a reduction in excess reserves over time. However, uncertainty remains for a large amount of existing conventional generation that may be vulnerable to retirement resulting from additional pending EPA regulations. These retirements reduce reserve margins over the course of the CPP implementation.³⁸

³⁷ 2011, 2012, and 2013LTRA data includes Future-Planned capacity additions <http://www.nerc.com/pa/RAPA/ra/Pages/default.aspx>.

³⁸ EPA Technical Support Document –Resource Adequacy and Reliability Analysis <http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-resource-adequacy-reliability.pdf>.

The EPA’s analysis assumes the electric system will maintain resource adequacy, even with the ongoing retirements from existing regulations, including MATS. In addition, because the proposed CPP will require the development of significant amounts of new generation in a short period, additional time for infrastructure development will be needed to support these new resources. The EPA’s modeling of a potential implementation scenario predicts an additional 40–48 GW of fossil-fired EGU retirements, and the addition of 21 GW of new NGCC resources.

With existing environmental regulations, the EPA’s base case projections indicate that total coal-fired capacity will decline rapidly from 309.6 GW in 2013 to just 245 GW by 2016, and 243 GW by 2025. The EPA’s base case—without implementation of the proposed CPP—assumes a significant reduction in coal-fired capacity by 2016: 27.2 GW beyond what is currently projected in the 2014LTRA reference case. According to the 2014LTRA reference case, an additional 44.2 GW of fossil-fired and nuclear capacity is projected to retire between 2014 and 2024.³⁹ These projections are based on the assumption that current environmental regulations will remain and do not account for potential impacts from the proposed CPP (Figure 7).

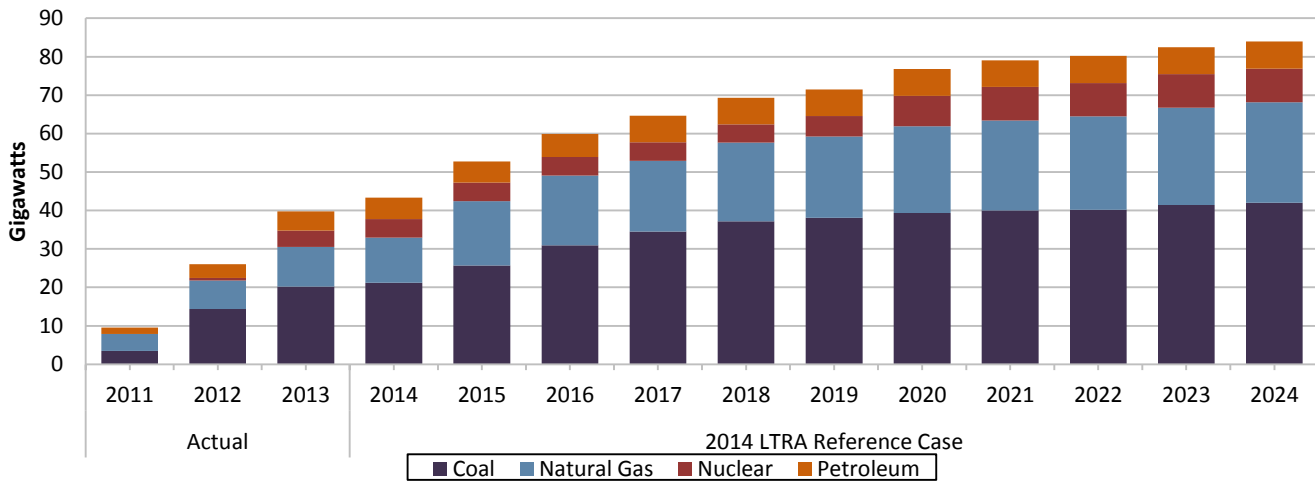


Figure 7. Cumulative Fossil-Fuel and Nuclear Retirements between 2011 and 2024 Total 83 GW

According to the EPA, the state implementation of Option 1 would result in a reduction in coal to 193 GW by 2025. Option 1 and the 2014LTRA reference case are shown in Figure 8 and Table 2.⁴⁰

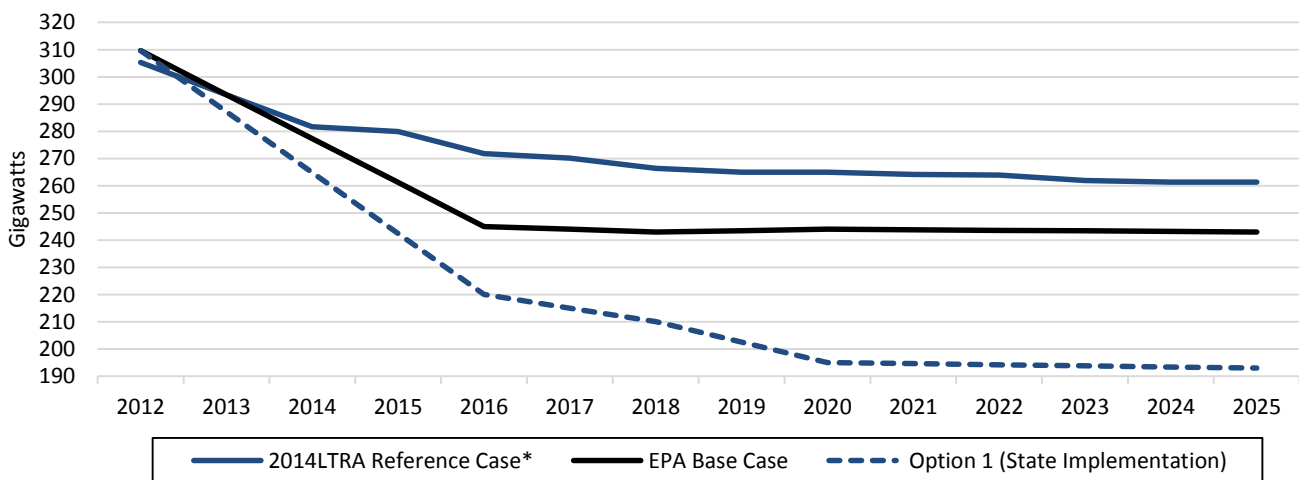


Figure 8. 2014LTRA Reference Case & EPA Power Plan Assumptions: Coal-Fired Capacity

³⁹ While the assessment period for the 2014LTRA is 2015–2024, projected retirements for 2014 are included in NERC’s 2014LTRA analysis.

⁴⁰ Regulatory Impacts Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants (June 2014) and supporting [IPM Model](#) documentation and data.

Table 2. 2014LTRA Reference Case & EPA Power Plan Assumptions

NERC 2014LTRA Reference Case - Total On-Peak Capacity (GW)	2016	2018	2020	2025*
Total Coal (Existing-Certain and Tier 1 Capacity Additions)	271.8	266.4	264.9	261.3
EPA Analysis of the Proposed Clean Power Plan - Total Coal Generating Capacity (GW)	2016	2018	2020	2025
Base Case	244.6	243.3	243.6	243.3
Option 1 (State Implementation)	219.7	210.4	195.1	193.1
EPA Assumed Coal Reduction Beyond NERC 2014LTRA Reference Case (GW)	2016	2018	2020	2025
Base Case	27.2	23.1	21.3	18.0
Option 1 (State Implementation)	52.1	56.0	69.8	68.2

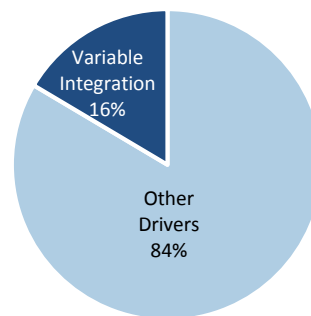
Transmission Planning and Timing Constraints

Long lead times for transmission development and construction require long-term system planning—typically a 10–15-year outlook. In addition to designing, engineering, and contracting transmission lines, siting, permitting, and various federal, state, provincial, and municipal approvals often take much longer than five years to complete. The CPP analysis assumes that adequate transmission capacity is available to deliver any resources located in, or transferred to, the region.⁴¹ Given the significant changes and locations anticipated to occur in the resource mix, it is likely that additional new transmission, or transmission enhancements, will be necessary in some areas. New transmission lines will be required to transport the amount of renewable generation coming online, particularly in remote areas, and that creates additional timing considerations. Further, as replacement generation is constructed, new transmission may be needed to interconnect new generation. Mitigating transmission constraints identified from the proposed EPA regulations in a timely way, consistent with CPP targets, presents a potential reliability concern. Construction of new interstate high-voltage lines would require transmission owners to confer to state and federal laws with respect to environment impacts, siting, and permitting. A construction timeline for a new high-voltage line can range from 5 to 15 years depending on the voltage class, location, and availability of highly skilled construction crews. The construction of transmission assets is a very lengthy process starting from planning to the actual physical construction. It is recommended that any policies that could potentially impact the reliable operation of the transmission system also consider the associated timeline for implementing plans.

Transmission Considerations with Additional VERs

The projected 30.8 GW of additional wind and solar resources will require additional transmission to reliably integrate these resources. VERs are often built in parts of North America that are distant from the point of interconnection to the transmission system. In many cases, the location of these variable resources only meets the minimum voltage support requirements. According to the 2014LTRA Reference Case, 16 percent of new transmission projects (under construction, planned, or conceptual) identify variable resource integration as a primary driver.

New Transmission Project Drivers



The location of additional transmission resources will be informed by the outcome of the transmission planning studies. The transmission planning process will not be able to fully incorporate the impacts of potential retirements until those resource addition requirements are made known to the system operator. For ISO/RTOs, this will likely not happen until the final state plans are developed.

To support variable generating capacity increases, the power industry would need to invest heavily to expand transmission capacity to access more remote areas with high-quality wind resources. Developing a resource mix that has sufficient ERSs to support integration and reliable BPS operation is also a consideration. Given the natural wind variability in these locations, incremental wind project resources would have relatively low capacity factors (20–35 percent) that would require complex financial decisions to support transmission capacity.

⁴¹ *Regulatory Impacts Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants* (June 2014) and supporting [IPM Model](#) documentation and data.

NERC anticipates that after the CPP guidelines are finalized in 2015, and SIPs are developed and approved by the EPA in 2016/2017, entities will work with their state utility commissions or other appropriate governing entities to assess resource and system options. Extensive transmission reliability screening assessments will be performed to support these decisions and will include comprehensive local and regional reliability analyses, which must be coordinated with states and neighboring entities. As resource decisions are made, reliability screening will transition into the established NERC reliability assessment processes. Consistent with the NERC Reliability Standards, transmission enhancements to address reliability constraints will be identified, incorporated into transmission expansion plans, and coordinated with other projects locally and regionally. Because committed transmission projects typically require three to five years to be completed, and often longer for major projects with significant right-of-way needs, NERC is concerned that reliability-related enhancements may not be able to be completed for a 2020 implementation.

Initial Regional Reliability Assessment of the Proposed CPP

Some regions started an initial reliability assessment of the proposed CPP focused on their respective footprints to better understand the plan's potential impacts. The initial analyses are slightly different in focus and are in varying stages of development. The key findings from recent MISO and SPP studies are provided below.

MISO

MISO focused primarily on generation capacity impacts. MISO, which is based on a 14.8 percent reserve margin requirement determined by the 1-day-in-10-year loss-of-load event, projects that in 2016 it will operate at the reliability level of approximately 2-days-in-10-year loss-of-load event, increasing the likelihood that resources will not be sufficient to serve peak demand. The number of expected days per year of a loss-of-load event is projected to increase throughout the assessment period. The proposed CPP could further exacerbate resource adequacy concerns in the MISO footprint unless additional replacement capacity is built in a timely fashion.⁴² Additionally, the analysis showed that the EPA's carbon proposal could put an additional 14,000 MW of coal capacity at risk of retirement. This amount is beyond the 12,600 MW within MISO's footprint that is slated to retire by the end of 2016 to comply with MATS.⁴³ The contributing factors driving the projected deficit include:

- Increased retirements and suspensions (temporary mothballing) due to EPA regulations and market forces and low natural gas prices
- Exclusion of low-certainty resources that were identified in the resource adequacy survey
- Exclusion of surplus of capacity in MISO South above the 1,000 MW transfer from the Planning Reserve Margin requirement (PRMR)⁴⁴
- Increased exports to PJM and the removal of non-Firm imports⁴⁵
- Inadequate Tier 1 capacity additions⁴⁶

⁴² Anticipated Reserve Margin includes operable capacity expected to be available to serve load during the peak hours with firm transmission. Prospective Reserve Margin operable capacity that could be available to serve load during the peak hour, but lacks Firm transmission and could be unavailable for a number of reasons.

⁴³ [MISO GHG Regulation Impact Analysis – Initial Study Results](#).

⁴⁴ For this assessment, 1,000 MW of capacity is transferred from the MISO South to the MISO North/Central Region pending the outcome of regulatory issues currently under FERC review.

⁴⁵ Capacity sales (imports and exports) in MISO depend on decisions of the respective resource owners, assuming that the tariff requirements are met (including planning of necessary transmission of both the buying and selling areas). Regarding the removal of non-Firm imports, the MISO market monitor double-counted non-Firm imports in the 2013LTRA reference case. These imports are accounted for in the Reference Margin Level (PRMR).

⁴⁶ In the MISO footprint, 91 percent of the load is served by utilities with an obligation to serve customers reliably and at a reasonable cost. Resource planning and investment in resources are part of state and locally jurisdictional integrated resource plans that only become certain upon the receipt of a Certificate of Public Convenience and Necessity (CPCN).

SPP

SPP looked at both generation capacity and transmission reliability impacts of the proposed CPP.⁴⁷ The initial study indicated that compliance with the carbon regulations, if implemented as modeled by the EPA, will not be possible without significant investment in new generation and associated major improvements to both the electric transmission and natural gas infrastructure to accommodate new generation. The results indicate that by 2020, SPP's anticipated reserve margin would be 5 percent, representing a capacity margin deficit of approximately 4,500 MW. By 2024, 10,000 MW beyond current plans would be needed to maintain their reserve margin. Given the 8- to 10-year timeline needed to plan for and construct these additional resources, SPP has concluded that there is not sufficient time to achieve compliance with the EPA's interim goals, and that widespread reliability impacts are likely.

The reliability issues identified in the initial studies will require significant upgrades to the transmission infrastructure to maintain system reliability, accommodate new generation or, when new generation is not warranted, to support the dispatch of the system in a manner significantly different from historical operations. Other ISO/RTOs, states, and Regions should prepare for the potential impacts to grid reliability, especially related to the time required to plan and build transmission infrastructure.

Reliability Assurance

NERC Reliability Standards and Regional Entity criteria must be met at all times to ensure reliable operation and planning of the BPS. Therefore, NERC supports policies developed by the EPA, FERC, the DOE, and state utility regulators that include a "reliability assurance mechanism," such as a reliability back-stop, to preserve BPS reliability and manage emerging and impending risks to the BPS.

Many utilities and ISO/RTOs have discussed a possible reliability safety valve similar to the one-year compliance extension that has been used to avoid retirement-related reliability impacts from the MATS compliance deadline. A reliability safety valve will be of limited utility if the EPA's proposal is implemented as currently designed, and it appears the EPA has far more flexibility under Section 111(d) than was available under the Section 112 program. Accordingly, a set of reliability assurance provisions that may include a reliability backstop, as well as other measures, would be recommended to maintain BPS reliability.

Stakeholders expressed to NERC staff their concerns regarding the need for additional time to mitigate the impacts of the carbon regulation. The proposed timeline does not provide enough time to develop sufficient resources to ensure continued reliable operation of the electric grid by 2020. To attempt to do so would increase the use of controlled load shedding and potential for wide-scale, uncontrolled outages. Additionally, policy changes may be required to ensure the Planning Coordinators and Transmission Planners perform the necessary studies and exercise the authority to implement transmission and related infrastructure solutions and assure that ERSs are provided in a timely manner.

⁴⁷ SPP Reliability Assessment of EPA 111(d) Clean Power Plan Rule <http://www.spp.org/publications/SPC%20Materials%20081914.pdf>.

**Direct Impacts to Resource Adequacy and Electric Infrastructure
Summary and Recommendations**

Fossil-Fired Retirements and Accelerated Declines in Reserve Margins: Despite low demand growth, NERC has highlighted resource adequacy concerns as projections continue to reflect declining reserve margins that fall below the Reference Margin Level in three assessment areas within the next five years.

- *The Regions, ISO/RTOs, and states should perform further analysis to examine the potential resource adequacy concerns.*

Transmission Planning and Timing Constraints: The proposed CPP implementation is currently scheduled to begin in mid-2016. Some reliability impacts could be mitigated by the construction of new (or enhancement of existing) transmission facilities; however, long lead times (e.g., 10 years) are required for transmission planning and construction.

- *The EPA and states, along with industry, should consider the time required to integrate potential transmission enhancements and additions necessary to address impacts of the proposed CPP.*

Regional Reliability Assessment of the Proposed CPP: To better understand its potential impacts, some Regions have started an initial reliability assessment of the proposed CPP focused on their respective footprints. The initial analyses are slightly different in focus and are in varying stages of development.

- *Other ISO/RTOs, states, and Regions should prepare for the potential impacts to grid reliability, especially related to the time required to plan and build transmission infrastructure.*

Reliability Assurance: NERC Reliability Standards and Regional Entity criteria must be met at all times to ensure reliable operation and planning of the BPS.

- *The EPA, FERC, the DOE, and state utility regulators should employ the array of tools at their disposal and their regulatory authority to develop reliability assurance mechanisms such as a reliability back-stop. These mechanisms include timing adjustments and granting extensions where there is a demonstrated reliability need.*

Impacts Resulting from the Changing Resource Mix

Coal Retirements Increase Reliance on Natural Gas for Electric Power

The electricity sector's growing reliance on natural gas raises concerns regarding the electricity infrastructure's ability to maintain system reliability when facing a constrained natural gas capacity for delivering natural gas to electric power generators. These concerns are already being articulated in light of gas-electric dependency studies and analyses, and include ISO/RTOs, electricity market participants, industrial consumers, national and regional regulatory bodies, and other government officials.⁴⁸ The extent of these concerns varies from region to region; however, concerns are most acute in areas where power generators rely on interruptible pipeline transportation as the natural gas use for generation rapidly grows.

Under the CPP, an accelerated shift in the power generation mix from coal to natural gas is expected to ensue. The EPA's state limitation calculations assume a 440 TWh/year shift to existing NGCC generation from coal (376 TWh/year) and older oil-gas steam (64 TWh/year) generators due to redispatched NGCC units up to a 70 percent capacity factor. In its *Regulatory Impact Assessment*, the EPA projects that the natural gas market portion of total U.S. power generation will grow from 29 percent energy in 2013 to 33–34 percent from 2020 to 2030. In an analysis of the CPP prepared by Energy Ventures Analysis (EVA), natural gas generation is found to increase by an additional 400–450 TWh/year and increase the gas generation energy market share to reach 35 percent in 2020, 39 percent in 2030, and 49 percent in 2040.⁴⁹

As reliance increases more on natural gas for both baseload and on-peak capacity, it is important to also examine potential risks associated with reduced diversity and increased dependence on a single fuel type. Currently, natural-gas-fired resources account for large portions of both the total and on-peak resource mix in several assessment areas when considering both existing capacity and planned additions (Table 3).

Table 3. Assessment Areas with Natural-Gas-Fired Capacity Accounting for Over One-Third of Existing Nameplate Capacity⁵⁰

Assessment Area	Nameplate Capacity (GW)		On-Peak Capacity (GW)		10-Year Nameplate Capacity Additions (GW)		
	Gas-Fired	Portion of Total	Gas-Fired	Portion of Total	Tier 1	Tier 2	Tier 3
FRCC	40.2	64%	33.9	63%	10.1	0.0	0.0
MISO	69.0	39%	58.7	41%	2.8	0.0	10.0
NPCC-New England	18.6	54%	13.3	43%	1.1	3.3	0.0
NPCC-New York	21.0	55%	14.2	40%	0.0	3.5	0.0
PJM	80.0	43%	56.5	32%	10.0	47.5	0.0
SERC-SE	31.2	47%	28.4	46%	0.0	0.0	2.6
SPP	32.3	40%	30.2	47%	1.1	0.7	5.7
TRE-ERCOT	48.4	54%	45.2	63%	4.9	21.5	0.0
WECC-CA/MX	47.7	61%	43.9	70%	5.5	6.2	0.9
WECC-RMRG	7.2	36%	6.2	41%	1.2	0.0	0.0
WECC-SRSG	19.5	47%	16.3	50%	0.6	1.0	3.0

With this shift toward more natural gas consumption in the power sector, the power industry will become increasingly vulnerable to natural gas supply and transportation risks. Extreme conditions, although rare, must be studied and integrated in planning to ensure a suitable generating fleet is available to support BPS reliability. While there are several plants with dual-fuel capability, the capability to switch to a secondary fuel can be limited during certain operating conditions.

Overdependence on a single fuel type increases the risk of common-mode or area-wide conditions and disruptions, especially during extreme weather events. Disruptions in natural gas transportation to power generators have prompted the gas and electric industries to seek an understanding of the reliability implications associated with increasing gas-fired generation. For example, adverse winter weather, such as that experienced during January 2014, provided signs of natural gas supply and deliverability risks.⁵¹ This can be a local issue in areas where there is already a heavy concentration of natural gas generation.

⁴⁸ See NERC's Special Reliability Assessments on electric and gas interdependencies for more information and recommendations: [Phase I](#) and [Phase II](#).

⁴⁹ Energy Ventures Analysis: FUELCAST – The Long-Term Outlook 2014, October 2014.

⁵⁰ Tier 1, 2, and 3 Capacity Category Definitions are provided in the *2014 Long-Term Reliability Assessment*.

⁵¹ NERC Polar Vortex Review Report

http://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf

While several gas pipeline construction projects are underway to increase gas deliverability, the CPP proposal accelerates the shift toward more natural gas generation and could create additional pipeline needs. The increased demand can be addressed with sufficient lead time (i.e., more than three years), which is needed to plan, collect contracts, permit, procure, and build new pipeline. To the extent that the CPP assumptions regarding natural-gas-fired capacity expansion and existing coal-fired generation retirements are achieved, the gas and electric sectors will lean more heavily on each other.

The Availability of Essential Reliability Services Is Strained by a Changing Resource Mix

The proposed CPP provides states and developers additional incentives to rapidly expand their non-hydro renewable capacity to displace existing coal generation. The state calculations assume that non-hydro renewable capacity could grow rapidly by 5 percent per year, from 218 TWh/year in 2012 to reach 523 TWh/year by 2030. This incremental renewable generation represents well over twice the energy currently supplied by VERs and would be dominated mostly by new wind, and to a lesser extent, new solar capacity.

In addition, wind projects will significantly increase the demand for reactive power and ramping flexibility. Ramping flexibility will increase cycling on conventional generation and often results in either increased maintenance hours or higher forced outage rates—in both cases, increased reserve requirements may result. While storage technologies may help support ramping needs, successful large-scale storage solutions have not yet been commercialized.⁵² Storage technologies support the reliability challenges that may be experienced when there is a large penetration of VERs, and their development should be expedited.

Based on industry studies and prior NERC assessments,⁵³ as the penetration of variable generation increases, maintaining voltage stability can be more challenging. Additional studies will be needed to further understand potential challenges that may indirectly result from the proposed CPP. In its role of assessing reliability, NERC commissioned the Essential Reliability Services Task Force (ERSTF) with members from NERC's Planning Committee and Operating Committee to study, identify, and analyze the planning and operational changes that may impact BPS reliability. NERC, under the ERSTF work plan and activities, has issued an initial assessment of ERSs that identifies ERS reliability building blocks as a foundational approach for further assessment and studies.⁵⁴

Increased Penetration of Distributed Energy Resources

The EPA projects that retail electricity prices will increase by \$1/MWh to \$18/MWh under the CPP⁵⁵ as a result of a combination of higher natural gas prices and the implementation of new carbon penalties on impacted fossil-fired generators.⁵⁶ As retail power prices increase, some existing customers may install DERs, when economically advantageous. Depending on the price advantage, the market penetration of DERs could be substantial, creating potential reliability impacts for grid operators that lack visibility and control of these resources. Given that DERs displace grid retail sales, DERs could become a larger grid capacity planning challenge since the grid will remain responsible for being the DER site's back-up power supplier. Reliability issues with large onsets of non-dispatchable resources have already created operational challenges in California, Hawaii, and Germany. Such experienced reliability challenges are:

- The loss of inertia and the loss of generating units used to control transient instability driven by the significant non-controllable generation and lack of sufficient attention to ERSs—Hawaii.

⁵² Pumped storage offers fast and large ramping capabilities to the BPS; however, increases in this technology is not likely due to land restrictions, permitting limitations, and environmental opposition. Less than 1 GW of pumped storage capacity is projected over the next 10 years.

⁵³ [NERC-CAISO Joint Report: Maintaining Bulk Power System Reliability While Integrating Variable Energy Resources – CAISO Approach](#); other industry reports include those developed by the [Integration of Variable Generation Task Force \(IVGTF\)](#); [Integrating Variable Renewable Energy in Electric Power Markets: Best Practices from International Experience \(Appendix D\)](#)

⁵⁴ NERC Essential Reliability Services Task Force - A Concept Paper on Essential Reliability Services that Characterize Bulk Power System Reliability http://www.nerc.com/comm/Other/essntlrbltysrvscstskfrcdL/ERSTF_Draft_Concept_Paper_Sep_2014_Final.pdf

⁵⁵ *Regulatory Impacts Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants* (June 2014) and supporting [IPM Model](#) documentation and data.

⁵⁶ According to EIA, closing coal plants will drive up natural gas prices by 150 percent over 2012 levels by 2040, this cost rise will cause electricity prices to jump seven percent by 2025 and 22 percent by 2040. Because natural gas prices are a key determinant of wholesale electricity prices, which in turn are a significant component of retail electricity prices. Accordingly, the cases with the highest delivered natural gas prices also show the highest retail electricity prices. [2014 Annual Energy Outlook](#).

- DERs only operate within frequency ranges that are in many cases close to nominal frequency and, therefore, frequency and voltage ride-through capabilities are needed—Germany.
- Increased wind and solar levels that mandate increased ramping, load-following, and regulation capability—this applies to both expected and unexpected net load changes. This flexibility will need to be accounted for in system planning studies to ensure system reliability—California.

Studies and Assessments Needed to Support Reliability

The following assessments are needed to form a complete reliability evaluation. Table 4 provides a list of the types of studies and analysis that must be done to demonstrate reliability, recognizing that the industry does not operate the grid without a thorough and complete analysis.

Table 4. Study and Assessment Types Needed for a Complete Reliability Evaluation

Local Reliability Assessments	Area/Regional Reliability Assessments
<ul style="list-style-type: none"> • Specific generator retirement studies • Specific generator interconnection studies • Specific generator operating parameters • Power flow (thermal, voltage) • Stability and voltage security • Offsite power for nuclear facilities 	<ul style="list-style-type: none"> • Resource adequacy • Power flow (regional) • Stability and voltage security (regional) • Gas interdependencies; pipeline constraints • Operating reserves and ramping • System restoration/blackstart

Impacts Resulting from the Changing Resource Mix Summary and Recommendations

Coal Retirements and the Increased Reliance on Natural Gas for Electric Power: As the industry relies more on natural-gas-fired capacity to meet electricity needs, close examination will be necessary to ensure risks have been fully identified and evaluated. Potential issues are most acute in areas where power generators rely on interruptible natural gas pipeline transportation.

- *Further coordinated planning processes between the electric and gas sectors will be needed to ensure a strong and integrated partnership. Coordinated planning processes should include considerations for pipeline expansion to meet the increased reliance on natural gas for electric generation—especially during the extreme weather events (e.g., polar vortex).*

The Changing Resource Mix and Maintaining Essential Reliability Services: The proposed CPP provides states and developers additional incentives to rapidly expand their non-hydro renewable capacity to displace existing coal generation. Resource adequacy assessments do not fully capture the ERSs needed to reliably operate the BPS and are generally limited to identifying supply and delivery risks.

- *ISO/RTOs, utilities, and Regions, with NERC oversight, should analyze the impacts to ERSs in order to maintain reliability. Additionally, system operators and ISO/RTOs need to develop appropriate processes, tools, and operating practices to adequately address operational changes on the system.*
- *NERC should perform grid-level performance expectations developed from a technology-neutral perspective to ensure ERS targets are met.*
- *The development of technologies (such as electricity storage) help support the reliability objectives of the BPS, and these technologies should be expedited to support variability and uncertainty on the BPS.*

Increased Penetration of Distributed Energy Resources: A potential risk in additional DERs is the temporary displacement of utility-provided service, which could create additional planning challenges, considering utilities must act as a secondary supplier of electricity.

- *ISO/RTOs and system planners and operators should consider the market penetration of DERs and potential reliability impacts due to the limited visibility and controllability of these resources.*

Conclusions

This report represents NERC's initial review of reliability concerns regarding the EPA's proposed Clean Power Plan (CPP) under Section 111(d) of the Clean Air Act. As the CPP is finalized and implemented, NERC will develop special reliability assessments in phases. This initial evaluation highlights the underlying CPP assumptions and identifies a range of potential reliability impacts of the CPP on the BPS. It is NERC's intention that this document be used as a platform by industry stakeholders and policy makers to discuss technically sound information about the potential reliability impacts of the proposed CPP.

The Building Block assumptions in the EPA's proposed CPP are critical to NERC's evaluation of the reliability impacts. NERC will provide independent assessments of the BPS under a wide range of conditions that reflect the implications of the proposed policy, varied resource mixes, and impacts to transmission and will share the results with the industry and states as they develop their implementation plans.

Recommendations

- 1. NERC should continue to assess the reliability implications of the proposed CPP and provide independent evaluations to stakeholders and policy makers.**

The NERC Board of Trustees endorsed a plan for the review and assessment of the reliability impacts of the EPA proposal at its August 2014 Board meeting. The NERC Planning Committee should lead NERC and industry efforts in conducting the reliability assessments and scenario analyses as identified in this report. NERC will work through its stakeholder process to solicit industry input on assessment approaches and assumptions as further special assessments and evaluations are developed.

- 2. Coordinated regional and multi-regional industry planning and analysis groups should immediately begin detailed system evaluations to identify areas of concern and work in partnership with policy makers to ensure there is clear understanding of the complex interdependencies resulting from the rule's implementation.**

Given the potential reliability concerns of the EPA's 2020 proposed implementation date, NERC encourages the states to begin operational and planning scenario studies, including resource adequacy, transmission adequacy, and dynamic stability, to assess economic and reliability impacts. A number of studies and analyses must be performed to demonstrate reliability, and industry must closely coordinate with the states to ensure the SIPs are aligned with what is technically achievable within the known time constraints. Additionally, industry should review system flexibility and reliability needs while achieving the EPA's emission reduction goals. As a result, states that largely rely on fossil-fuel resources might need to make significant changes to their power systems to meet the EPA's target for carbon reductions while maintaining system reliability.

- 3. If the environmental goals are to be achieved, policy makers and the EPA should consider a more timely approach that addresses BPS reliability concerns and infrastructure deployments.**

NERC Reliability Standards and Regional Entity criteria must be met at all times to ensure reliable operation and planning of the BPS. Based on NERC's initial review, more time would be needed in certain areas to ensure resource adequacy, reliability requirements, and infrastructure needs are maintained. The EPA, FERC, the DOE, and state utility regulators should consider their regulatory authority to make timing adjustments and to grant extensions to preserve BPS reliability. NERC supports policies that include a reliability assurance mechanism to manage emerging and impending risks to the BPS, and urges policy makers and the EPA to ensure that a flexible and effective reliability assurance mechanism is included in the rule's implementation.

ATTACHMENT C



ERCOT Analysis of the Impacts of the Clean Power Plan

ERCOT Analysis of the Impacts of the Clean Power Plan

The Electric Reliability Council of Texas (ERCOT) is the independent system operator (ISO) for the Texas Interconnection, encompassing approximately 90% of electric load in Texas. ERCOT is the independent organization established by the Texas Legislature to be responsible for the reliable planning and operation of the electric grid for the ERCOT interconnection. Under the North American Electric Reliability Corporation (NERC) reliability construct, ERCOT is designated as the Reliability Coordinator, the Balancing Authority, and as a Transmission Operator for the ERCOT region. ERCOT is also registered for several other functions, including the Planning Authority function.

In June 2014, the U.S. Environmental Protection Agency (EPA) proposed the Clean Power Plan, which calls for reductions in the carbon intensity of the electric sector. The Clean Power Plan would set limits on the carbon dioxide (CO₂) emissions from existing fossil fuel-fired power plants, calculated as state emissions rate goals. For Texas, EPA has proposed an interim goal of 853 lb CO₂/MWh to be met on average during 2020-2029, and a final goal of 791 lb CO₂/MWh to be met from 2030 onward. EPA calculated the state-specific goals using a set of assumptions about coal plant efficiency improvements, increased production from natural gas combined cycle units, growth in renewables generation, preservation of existing nuclear generation, and growth in energy efficiency.

ERCOT has evaluated the potential implications of the proposed Clean Power Plan for grid reliability and conducted a modeling analysis of the impacts to generation resources and electricity costs in the ERCOT region. Based on this analysis, ERCOT anticipates that implementation of the proposed Clean Power Plan will have a significant impact on the planning and operation of the ERCOT grid. ERCOT estimates that the proposed CO₂ emissions limitations will result in the retirement of between 3,300 MW and 8,700 MW of coal generation capacity, could result in transmission reliability issues due to the loss of generation resources in and around major urban centers, and will strain ERCOT's ability to integrate new intermittent renewable generation resources. The Clean Power Plan will also result in increased energy costs for consumers in the ERCOT region by up to 20% in 2020, without accounting for the costs of transmission upgrades, procurement of additional ancillary services, energy efficiency investments, capital costs of new capacity, and other costs associated with the retirement or decreased operation of coal-fired capacity in ERCOT. This summary report describes the results of ERCOT's analyses.

1. Summary of ERCOT Concerns with the Clean Power Plan

ERCOT approaches this analysis from the perspective of an independent grid operator in a competitive market which has achieved significant success in using competition to drive efficient outcomes. Existing market policies and investments in transmission in ERCOT have incentivized market participants to maximize the efficiency of the generating fleet and develop new technologies including renewable generation. With recent investments in transmission, more than 11 GW of wind capacity have been successfully integrated into the ERCOT grid. The ERCOT region maintains a forward-looking open market and provides affordable and reliable electricity to consumers in Texas.

ERCOT's primary concern with the Clean Power Plan is that, given the ERCOT region's market design and existing transmission infrastructure, the timing and scale of the expected changes needed to reach the CO₂ emission goals could have a harmful impact on reliability. Specifically, implementation of the Clean Power Plan in the ERCOT region, particularly to meet the Plan's interim goal, is likely to lead to reduced grid reliability for certain periods and an increase in localized grid challenges. There is a natural pace of change in grid resources due to advancing cost effective technologies and changing market conditions.

This pace can be accelerated, but there is a limit to how fast this change can occur within acceptable reliability constraints. It is unknown based on the information currently available whether compliance with the proposed rule can be achieved within applicable reliability criteria and with the current market design. Nevertheless, there are certain grid reliability and management challenges that ERCOT will face as a result of the resource mix changes that the proposed rule will induce:

- The anticipated retirement of up to half of the existing coal capacity in the ERCOT region will pose challenges to reliable operation of the grid in replacing the dispatchable generation capacity and reliability services provided by these resources.
- Integrating new wind and solar resources will increase the challenges of reliably operating all resources, and pose costs to procure additional regulating services, improve forecast accuracy, and address system inertia issues.
- Accelerated resource mix changes will require major improvements to ERCOT's transmission system, posing significant costs not considered in EPA's Regulatory Impact Analysis.

These issues highlight the need for the final rule to include a process to effectively manage electric system reliability issues that may arise due to implementation of the Clean Power Plan, as well as include more implementation timeline flexibility to address each state's or region's unique market characteristics. With respect to the need to manage reliability issues, ERCOT supports the ISO/RTO Council (IRC) proposal for the inclusion of a reliability safety valve process in the context of the CO₂ rule, as well the need for states to consult with ISOs/RTOs during the development of State Plans.

2. Results of ERCOT Modeling

This summary report draws on results from an ongoing analysis of the expected impacts of several recently finalized and proposed environmental regulations on grid reliability in the ERCOT region. The study uses stakeholder-vetted planning processes and methodologies consistent with the regional Long-Term System Assessment studies conducted by ERCOT. A full report on this environmental regulatory impact study will be released in mid-December 2014.

The sections that follow describe the modeling methodology and summarize the results from the modeling analysis. Next, the modeling results are compared to those obtained by EPA in its analysis of the Clean Power Plan. This is followed by a discussion of the impacts of these results for grid reliability and transmission infrastructure. The report concludes with a discussion of cost impacts.

2.1. Modeling Methodology

ERCOT evaluated the proposed Clean Power Plan using two methodologies. First, ERCOT considered a scenario with the Clean Power Plan limits applied as a constraint, to allow the long-term simulation model to select the most cost-effective way to achieve the proposed carbon intensity from electric generating resources. Second, a carbon emission fee was used to cause the system to achieve the proposed standard over the allotted compliance period. The benefit of the first approach is that it would be expected to minimize the overall cost to the system, and should lead to results that are comparable to the methodology utilized by the EPA in its analysis of the rule impacts. However, it may not be a change that is achievable within the current electricity market design in ERCOT. For this reason, ERCOT also modeled emissions fee scenarios. Though a carbon price is not an explicit component of EPA's proposal, it is one option that Texas could use to comply with the limits, and is included here in order to

assess the system impacts of a potential approach to compliance. In both cases, ERCOT evaluated the limits in the Clean Power Plan by applying the proposed emissions rate limits for Texas (in lb/MWh) to the ERCOT system.

ERCOT modeled four distinct scenarios over the timeframe 2015-2029 to evaluate the implications of the Clean Power Plan on reliability in the region:

1. **Baseline** – This scenario estimates a baseline of the ERCOT system under current market trends against which anticipated Clean Power Plan changes will be compared.
2. **CO₂ Limit** – This scenario applied the limits in the Clean Power Plan to the ERCOT system to determine the most cost-effective way to comply with the limits. This scenario did not place a price on CO₂ emissions.
3. **\$20/ton CO₂** – This scenario applied a \$20/ton price on carbon dioxide emissions to the ERCOT system. With a \$20/ton CO₂ price, the ERCOT system attains an emission intensity of 904 lb CO₂/MWh in 2020 and 877 lb CO₂/MWh in 2029 – above both the interim and final goals.
4. **\$25/ton CO₂** – This scenario applied a \$25/ton price on carbon dioxide emissions to the ERCOT system. With a \$25/ton CO₂ price, the ERCOT system attains an emission intensity of 840 lb CO₂/MWh in 2020 and 792 lb CO₂/MWh in 2029 – below the interim goal and approximately meeting the final goal.¹

It should be noted that ERCOT did not require the system to maintain a specific reserve margin in the modeled scenarios. The target reserve margin criterion in ERCOT is not binding and it is possible that market conditions will result in a lower reserve margin than the recommended level. By contrast, EPA's modeling, described later, required that ERCOT maintain a 13.75% reserve margin. This difference in assumptions results in different amounts of capacity additions, and has implications for grid reliability.

This study uses stakeholder-vetted assumptions consistent with ERCOT's Long Term System Assessment (LTSA).² These assumptions include the anticipated expiration of the Production Tax Credit (PTC) and phase out of the Investment Tax Credit (ITC). Natural gas price projections are based on an average of the Energy Information Administration (EIA) Annual Energy Outlook (AEO) 2014 forecast and the forecast from Wood Mackenzie, shown in Figure 1. The same natural gas price assumptions were applied in all scenarios.

¹ ERCOT did not attempt to calculate a carbon price to precisely meet the emissions limits. Instead, ERCOT found a carbon price range within which the system is anticipated to achieve the Clean Power Plan emissions standards.

² For more information, visit ERCOT's Regional Planning Group (RPG) website at <http://www.ercot.com/committees/other/rpg/index.html>.

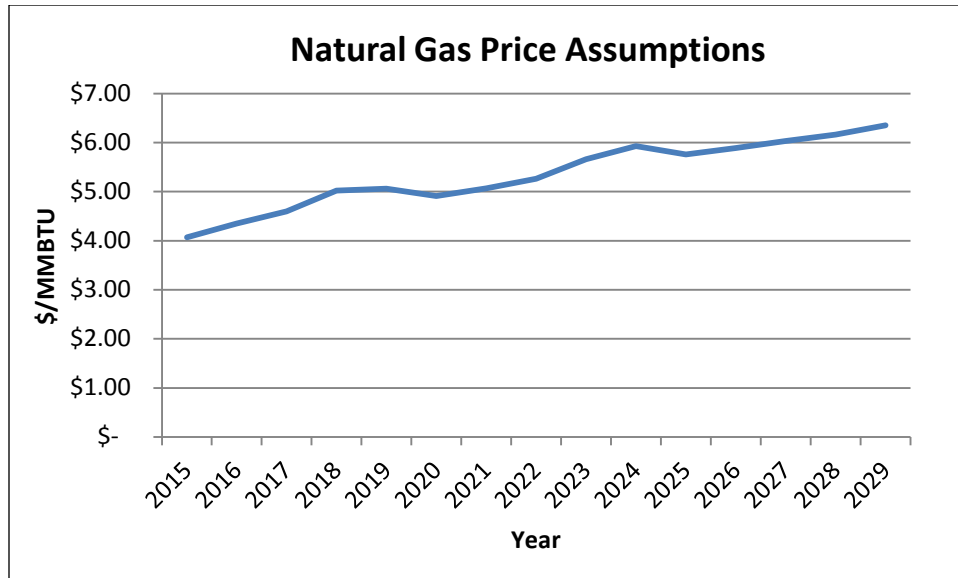


Figure 1: Natural Gas Price Assumptions

ERCOT assumed capital costs consistent with those used in the LTSA, with the exception of solar capital costs. After review of information provided by stakeholders and updated reports by the National Renewable Energy Laboratory (NREL) and Lazard, it is clear that solar capital costs continue to decline at a rapid rate. To be more in line with these lower costs, solar capital costs were lowered in the near term years of this study to reflect this latest information. ERCOT estimated solar capital costs based on a review of information provided by Lazard,³ Solar Energy Industries Association,⁴ and Citi Research.⁵ Figure 2 displays the solar capital costs used by ERCOT in this analysis. Capital costs for all other generation technologies were taken from the EIA AEO 2014.

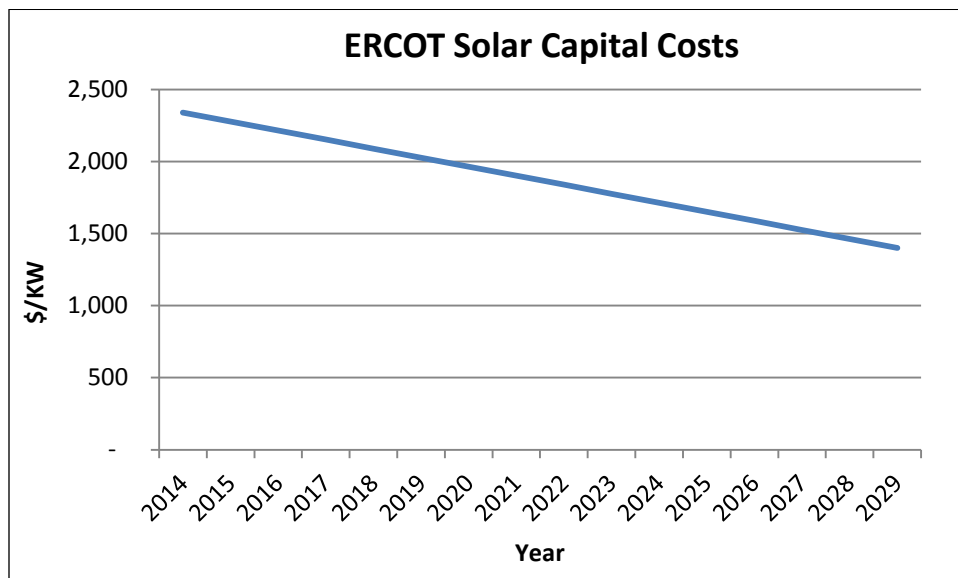


Figure 2: ERCOT Solar Capital Costs

³ Lazard. *Lazard's Levelized Cost of Energy Analysis – Version 8.0*, September 2014. Available from <http://www.lazard.com/pdf/levelized%20cost%20of%20energy%20-%20version%208.0.pdf>.

⁴ Greentech Media, Inc and Solar Industries Association. *U.S. Solar Market Insight Report*. Q1 2014. Confidential Report.

⁵ Citi Research. *Launching on the Global Power Sector: The Sun Will Shine but Look Further Downstream*. February 6, 2013. Confidential Report.

With regard to the generation fleet, ERCOT modeled the capacity listed in ERCOT’s May 2014 Capacity, Demand, and Reserves (CDR) report,⁶ with the addition of planned generation resources that had started construction by Summer 2014, as well as the full capacity of Private Use Networks (PUNs).⁷ Table 1 shows the baseline capacity assumptions used in the modeling. Generation from wind and solar resources was modeled based on wind and solar production profiles that estimate the amount of wind and solar resources available for every hour of the year, based on the 2010 weather year. For wind, ERCOT used county-specific wind production profiles provided by AWS Truepower. The solar production profiles were provided by URS and are based on data from weather stations in West Texas.

Table 1: Baseline Capacity Assumptions

Fuel Type	Capacity (MW)
Nuclear	5,200
Coal	19,900
Natural Gas	58,900
Wind	16,700
Solar	250
Hydro	500
Other	1,000
Total	102,450

Within the scenarios, ERCOT varied some assumptions pertaining to implementation of the Clean Power Plan and compliance with other environmental regulations. First, scenarios 2-4 required compliance with the Cross-State Air Pollution Rule (CSAPR) limits, imposed as a limit in Scenario 2 and as an emission fee in scenarios 3 and 4.⁸ Second, due to data availability limitations, ERCOT was only able to model through 2029. In scenario 2, to approximate compliance with the final goal in the Clean Power Plan, ERCOT applied the final CO₂ limit as a constraint over 2028-2029, and the interim CO₂ limit over 2020-2027. In this scenario, the ERCOT interconnection was required to meet the applicable emission rate goal in each year; the other scenarios did not include this requirement.

Finally, in the baseline scenario ERCOT assumed energy efficiency savings at 1% of load for all modeled years, consistent with current levels of energy efficiency as measured by the Electric Utility Marketing Managers of Texas (EUMMOT).⁹ For scenarios 2-4, ERCOT assumed growth in energy efficiency savings to a level of 5% by 2029. EPA’s building blocks assumed Texas could achieve a cumulative 9.91% savings from energy efficiency by 2029. ERCOT did not elect to use the energy efficiency savings level estimated by EPA because this level of energy efficiency is not consistent with current trends in energy efficiency in Texas.¹⁰ ERCOT’s more moderate assumption is consistent with the approach taken by the Mid-Continent Independent System Operator (MISO) in its analysis of the impacts of the Clean Power Plan.¹¹ MISO modeled three energy efficiency assumptions: base energy efficiency trends, EPA’s Building Block 4, and 50% of EPA’s Building Block 4. ERCOT’s approach of using 5% is consistent with the third assumption modeled by MISO, and represents a moderate, and more realistic, energy efficiency growth assumption, between the current level of savings and EPA’s goal.

⁶ ERCOT’s *Report on the Capacity, Demand, and Reserves in the ERCOT Region* is available at <http://www.ercot.com/gridinfo/resource/index.html>.

⁷ In addition to PUN capacity, ERCOT also separately modeled PUN load.

⁸ ERCOT assumed an SO₂ emission price of \$800/ton, an ozone season NO_x emission price of \$1,600/ton, and an annual NO_x emission price of \$1,000/ton. ERCOT estimated these prices based on a series of model iterations as part of this study.

⁹ EUMMOT’s *Energy Efficiency Accomplishments Report* is available at <http://www.texasefficiency.com/index.php/publications/reports>.

¹⁰ For information about energy efficiency trends in Texas, visit the EUMMOT website at <http://www.texasefficiency.com/>.

¹¹ MISO. *GHG Regulation Impact Analysis*, July 30, 2014. Available from <https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/PAC/2014/20140730/20140730%20PAC%20Item%2012a%20GHG%20Regulation%20Impact%20Analysis.pdf>.

2.2. Summary of Modeling Results

The modeling results for the four scenarios indicate incremental unit retirements and incremental renewable capacity additions in the CO₂ limit and carbon price scenarios compared to the baseline. In the CO₂ limit and carbon price scenarios, the model retired 2,900 MW to 5,000 MW of capacity incremental to retirements in the baseline, as shown in Table 2.

Most of the incremental retirements were coal units, with between 3,300 MW and 5,700 MW of incremental coal unit retirements compared to the baseline. The amount of incremental coal retirements in

the carbon scenarios is higher than the total amount of incremental retirements because of natural gas steam retirements that occur in the baseline but not in the carbon scenarios. The fewer retirements of natural gas steam units in the carbon scenarios reflects the impact of both the CSAPR and carbon dioxide limits on production from coal units, improving the economics of natural gas steam units during this period. Note that in the baseline, 800 MW of coal capacity retires, corresponding to the announced retirement of CPS Energy's J. T. Deely units 1 and 2 in 2018.

Table 2: Unit Retirements by 2029

Generation Technology Type	Baseline	CO ₂ Limit	CO ₂ \$20/ton	CO ₂ \$25/ton
Retired Gas Steam (MW)	2,000	1,600	1,600	1,300
Retired Coal (MW)	800	4,100	4,100	6,500
Total Retirements (MW)	2,800	5,700	5,700	7,800

The CO₂ limit and carbon price scenarios also resulted in between 5,500 and 7,100 MW incremental renewable capacity additions compared to the baseline, which itself saw 9,900 MW of new solar capacity.¹² As noted previously, ERCOT assumed the expiration of the PTC as per current law, which is the reason there are no wind capacity additions in the baseline scenario. All three scenarios built less natural gas-fired capacity compared to the baseline. Table 3 summarizes the capacity additions for each scenario.

Table 3: Capacity Additions by 2029

Generation Technology Type	Baseline	CO ₂ Limit	CO ₂ \$20/ton	CO ₂ \$25/ton
Wind (MW)	0	3,400	2,800	3,500
Solar (MW)	9,900	12,500	12,600	13,500
Combined Cycle (MW)	0	0	0	1,300
Combustion Turbine (MW)	4,600	1,000	1,000	1,000
Total (MW)	14,500	16,900	16,400	19,300

As shown in Figure 3, the retiring coal and gas steam capacity would be replaced by solar, wind, and natural gas-fired capacity by 2029, taking into account the contribution of energy efficiency measures. However, within the modeled timeframe there are some years for which the ERCOT capacity reserve margin may be

considerably less than historically targeted for reliability, as capacity retires before new resources come online and energy savings from energy efficiency measures begin to materialize. In the model results, these shortages occur towards the beginning of the compliance timeframe, between 2020 and 2022.

During this timeframe, the modeled retirements and capacity additions result in a reserve margin 2 to 3% below the reserve margin in the baseline scenario for these years, in the CO₂ limit and \$20/ton CO₂

¹² The solar capacity additions modeled in this study are consistent with the results of ERCOT's 2013 Long-Term Transmission Analysis, which indicated that large amounts of solar would be economic in ERCOT after 2020. For more information, visit ERCOT's Long-Term Study Task Force website at <http://www.ercot.com/committees/other/lts/index.html>.

scenarios.¹³ By 2029, the reserve margin in these scenarios is comparable to the baseline scenario. The reserve margins are generally higher in the \$25/ton CO₂ scenario, because the increased price on CO₂ results in increased capacity additions. As previously described, ERCOT did not require the simulation model to maintain a specific reserve margin in the four scenarios.

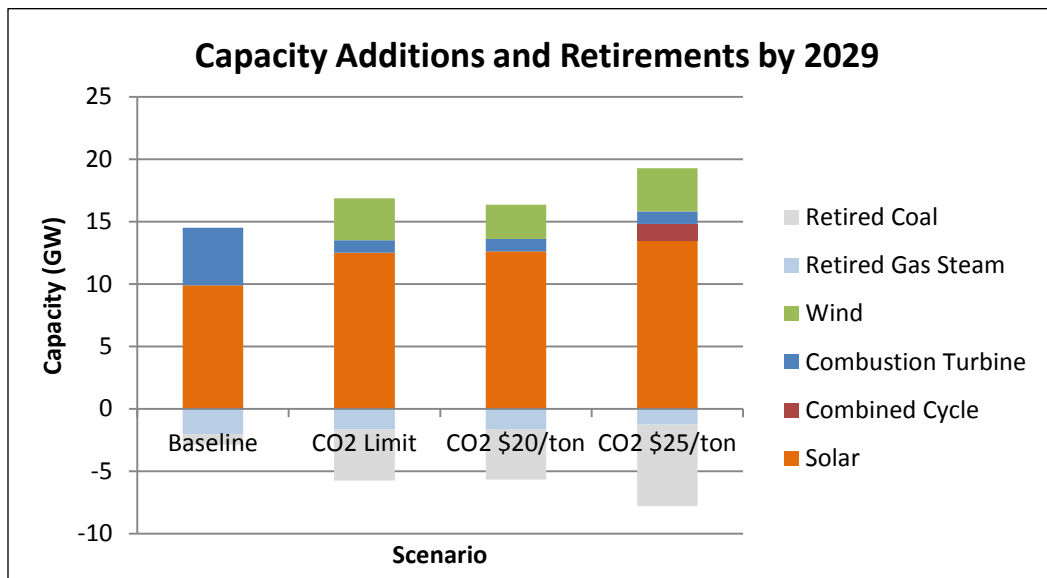


Figure 3: Capacity Additions and Retirements by 2029

With the modeled retirements and capacity additions, the generation mix in the modeling results shifts towards increased generation from natural gas and renewable generation resources, and decreased generation from coal generation resources. Table 4 and Table 5 show the generation mix in 2020 and 2029, respectively, across the four scenarios. In 2020, natural gas-fired units contribute 60% or more of total energy in the carbon scenarios, up from 44% in the baseline. Coal generation correspondingly decreases to 11 to 14%, from a baseline of 32% of total generation. By 2029, renewable generation accounts for 21 to 22% of total generation in the three CO₂ scenarios, up from 17% of total 2029 generation in the baseline scenario.

Table 4: Generation Mix in 2020 (% of MWh)

Fuel Type	Baseline	CO ₂ Limit	CO ₂ \$20/ton	CO ₂ \$25/ton
Natural Gas (%)	44	60	60	63
Coal (%)	32	14	14	11
Wind (%)	12	15	15	16
Solar (%)	< 1	< 1	< 1	< 1
Nuclear (%)	10	10	10	10
Other (%)	1	< 1	< 1	< 1

Table 5: Generation Mix in 2029 (% of MWh)

Fuel Type	Baseline	CO ₂ Limit	CO ₂ \$20/ton	CO ₂ \$25/ton
Natural Gas (%)	45	53	53	55
Coal (%)	29	16	16	13
Wind (%)	11	14	14	14
Solar (%)	6	7	7	8
Nuclear (%)	9	9	9	9
Other (%)	< 1	< 1	< 1	< 1

¹³ The ERCOT reserve margin is calculated using wind capacity contribution values of 12% for non-coastal resources and 56% for coastal resources, consistent with the ERCOT Board approved methodology outlined in Nodal Protocol Revision Request (NPRR) 611. The data used to calculate the wind capacity contribution is available on the ERCOT website at <http://www.ercot.com/gridinfo/resource/index.html>. For solar capacity, ERCOT assumes a 70% capacity contribution based on the modeled solar output during peak hours (16:00 to 18:00) as a percentage of total installed capacity.

The modeling results indicate significantly higher generation from natural gas-fired resources under the Clean Power Plan. This trend is most distinct early in the compliance period, before the bulk of solar capacity additions and energy efficiency savings materialize. In 2020, natural gas consumption by the power sector is 35 to 50% higher annually in the carbon scenarios compared to the baseline, as shown in Figure 4. By 2029, natural gas consumption is 15 to 20% above the amount consumed annually in the baseline.

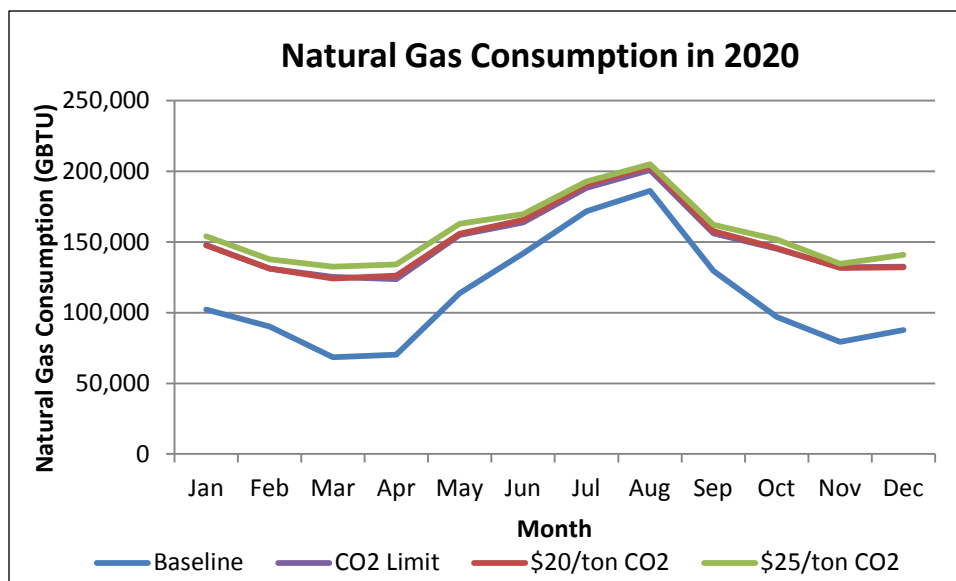


Figure 4: Natural Gas Consumption in 2020

The four scenarios resulted in different levels of carbon intensity. As noted previously, the \$20/ton CO₂ scenario resulted in a carbon intensity above both the interim and final emissions limits in the Clean Power Plan, while the

Table 6: Carbon Dioxide Emissions Intensity

CO ₂ Intensity	Baseline	CO ₂ Limit	CO ₂ \$20/ton	CO ₂ \$25/ton
2020 CO ₂ Intensity (lb/MWh)	1,175	853	905	840
2029 CO ₂ Intensity (lb/MWh)	1,089	791	877	792

\$25/ton CO₂ scenario resulted in a carbon intensity below the interim goal and approximately meeting the final goal (see Table 6 and Figure 5). In the baseline scenario, ERCOT's carbon intensity is at 1,175 lb/MWh in 2020 and 1,089 lb/MWh in 2029. The projected emissions intensity for ERCOT in the baseline is below the Clean Power Plan emissions rate goals for 19 other states, an indication of the impact that existing market policies and investments in transmission in Texas have had on maximizing the efficiency of the generating fleet and integrating new technologies including renewable generation.

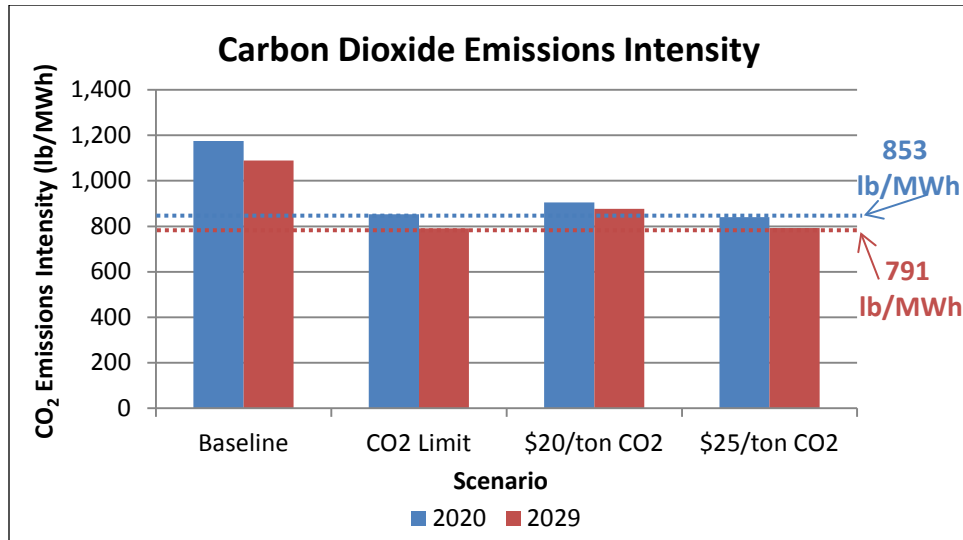


Figure 5: CO₂ Emissions Intensity

2.3. Comparison to EPA’s Modeling Results

EPA conducted an analysis of the Clean Power Plan by applying the carbon limits to the U.S. electric system, and allowing their simulation model to solve for the most cost-effective solution. The results referenced here are for EPA’s “Option 1 State Compliance” scenario, as compared to the base case.¹⁴

EPA’s modeling results predict that there may be 9 GW of coal unit retirements in ERCOT due to the Clean Power Plan – most occurring before the initial 2020 compliance date. ERCOT’s modeling predicted up to 6 GW of coal unit retirements, but ERCOT believes that there could be up to 9 GW of coal unit retirements resulting from the Clean Power Plan due to additional factors not considered in the model (discussed in Section 3.1). Similarly, both EPA’s and ERCOT’s modeling saw a major shift in the generation mix in 2020 to comply with the interim goal, with substantially increased production from natural gas generation resources and substantially decreased production from coal generation resources. However, EPA’s modeling resulted in much fewer renewable capacity additions compared to ERCOT’s results and significantly more new natural gas generating capacity. The lower amount of renewable capacity additions is due to EPA’s use of higher capital cost assumptions for new solar capacity. The larger amount of natural gas capacity additions is due in part to EPA’s modeling requirement that ERCOT maintain a 13.75% reserve margin, as discussed previously. EPA’s modeling predicts more than 10 GW of new natural gas capacity by 2030 in the state compliance scenario, whereas ERCOT’s carbon scenarios added 1 to 2 GW of new natural gas capacity.

3. Impact on Reliability

The modeling results raise two reliability concerns associated with implementation of the Clean Power Plan in ERCOT. These concerns are associated with the impacts of unit retirements and increased levels of renewable generation on the ERCOT grid.

3.1. Impact of Unit Retirements

As previously described, the model retired between 3,300 and 5,700 MW of coal-fired capacity in the carbon scenarios, relative to the baseline. However, these results represent a lower bound on the

¹⁴ EPA’s modeling run files are available from <http://www.epa.gov/airmarkets/powersectormodeling/cleanpowerplan.html>.

number of potential coal unit retirements due to the logic used to retire units in the model, generic unit cost information, and the impacts of other factors not considered by the model. ERCOT directed the model to retire capacity at the point when generic operating and fixed costs exceed revenues. However, in the modeling results for the carbon scenarios, there are several units operating at low revenues and/or low capacity factors that would likely be retired, especially when other non-modeled factors are taken into account. One important factor not considered in the modeling is the capital and operating cost impacts of other pending environmental regulations including the Mercury and Air Toxics Standard, the Regional Haze program, the 316(b) Cooling Water Intake Structures Rule, and the coal ash rules.

Based on a review of capacity factors and operating revenues for the remaining coal units ERCOT anticipates the retirement of an additional 2,000 MW of coal capacity and the seasonal mothball of 1,000 MW of coal capacity beyond what is specified in the model output, compared to the \$25/ton CO₂ modeled scenario. These results indicate the overall impact to the current coal fleet will be the retirement or seasonal mothballing of between 3,300 MW and 8,700 MW.

The accelerated retirement or suspended operations of coal resources would pose challenges to maintaining the reliability of the ERCOT grid. Coal resources provide essential reliability services, including reactive power and voltage support, inertial support, frequency response, and ramping capability. The retirement of coal resources will require reliability studies to determine if there are any voltage/reactive power control issues that can only be mitigated by those resources; how to replace frequency response, inertial support, and ramping capability provided by retiring units; and the necessity of potential transmission upgrades, which will be discussed later in this document.

The model also predicted the retirement of 1,300 to 1,600 MW of natural gas steam capacity in the carbon scenarios, which is less than the 2,000 MW retired in the baseline scenario. The fewer retirements of natural gas steam units in the carbon scenarios reflects the impact of both the CSAPR and carbon dioxide limits on production from coal units, which improves the economics of natural gas steam units during this period. However, as with coal resources, there are a number of factors that may result in additional natural gas steam unit retirements compared to those found by the model. ERCOT estimates that an additional 1,500 to 4,500 MW of natural gas steam capacity may be at risk of retirement based on low net revenues in the model results combined with the need to comply with the 316(b) rule, CSAPR, and other environmental regulations.

The modeling results indicate that generation from retiring coal capacity will in large part be replaced by increased production from existing natural gas capacity. Though ERCOT is not currently affected by natural gas supply issues, the increased use of natural gas nationally could lead to increased market dislocations, such as seen in the winter of 2013-2014. Depending on the magnitude of these issues, there could be implications for maintaining reliable natural gas supply in ERCOT for electric generation in the future.

It should also be noted that prospective compliance with the Clean Power Plan in 2020 will impact decisions generation resources make now about investments to comply with other pending environmental regulations. With the implementation of the Clean Power Plan to consider, owners of generation resources in Texas may choose to retire units early rather than install control technology retrofits for compliance with the Mercury and Air Toxics Standard (MATS), the Regional Haze Program, or the 316(b) Cooling Water Intake Structures rule. For example, the compliance date for the MATS rule is April 2015, but several coal-fired units in Texas have received a one-year compliance extension from the Texas Commission on Environmental Quality (TCEQ). The pending market impacts due to the Clean Power Plan could result in resource owners deciding to retire these units rather than invest in the retrofit technology required to achieve compliance with MATS. Similarly, it is anticipated that EPA will

issue a Federal Implementation Plan (FIP) for Texas for the Regional Haze program in the coming weeks. Depending on the FIP requirements, generators may need to make similar decisions about whether to make significant investments in control technology retrofits or instead retire their units, in light of eventual compliance with the Clean Power Plan. With earlier retirements of fossil fuel-fired capacity, ERCOT could experience the aforementioned grid reliability challenges well before the Clean Power Plan's first compliance date in 2020.

3.2. Impact of Renewables Integration

Integrating new wind and solar resources will increase the challenges of reliably operating the ERCOT grid. In 2013, almost 10% of the ERCOT region's annual generation came from wind resources. In order to accommodate this level of intermittent generation, ERCOT has needed to evaluate impacts on operational reliability and improve wind output forecasting capabilities. The increased penetration of intermittent renewable generation, as projected by these modeling results, will increase the challenges of reliably operating all generation resources. If there is not sufficient ramping capability and operational reserves during periods of high renewable penetration, the need to maintain operational reliability could require the curtailment of renewable generation resources. This would limit and/or delay the integration of renewable resources, leading to possible non-compliance with the proposed rule deadlines.

Based on the \$25/ton CO₂ scenario, intermittent renewable generation sources will contribute 22% of energy on an annual basis in 2029. However, during 628 hours of the year intermittent generation will serve more than 40%¹⁵ of system load. During 128 hours instantaneous renewable penetration will be higher than 50%, and the peak instantaneous renewable penetration from the model results is 61%. The significant change from present experience is that the highest renewable penetration hours will be driven by maximum solar production during relatively high wind periods. These periods occur during the day (8 a.m. to 5 p.m.), as opposed to early morning hours (usually 2 to 4 a.m.), as currently experienced in ERCOT. The high instantaneous renewable penetration hours in 2029 occur year round except for the July-September period. Figure 6 shows generation output by fuel type for the days with the highest instantaneous penetration of renewables in 2029 in the \$25/ton CO₂ scenario.

¹⁵ The record in the ERCOT region for wind penetration occurred on March 31, 2014 at 2:00 a.m., when wind resources met 39.44% of load.

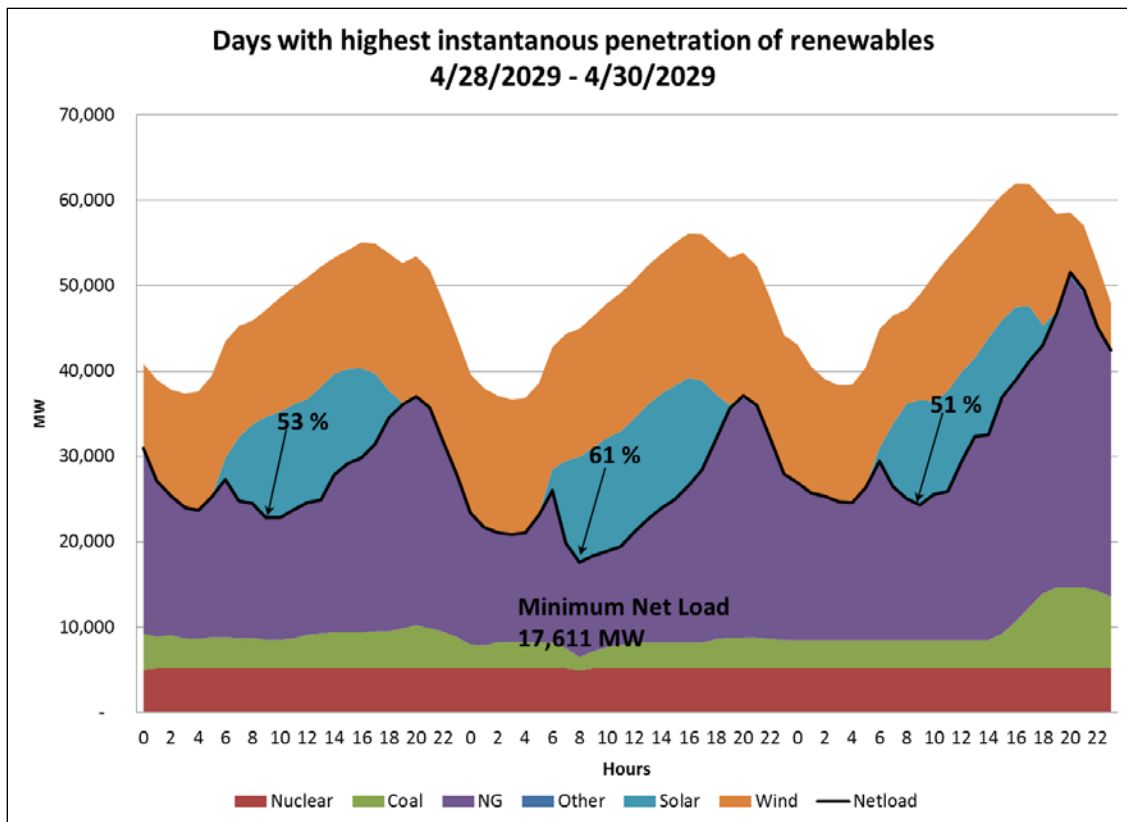


Figure 6: Days with Highest Instantaneous Penetration of Renewables

Due to load growth, the lowest net load (defined as total load minus generation from intermittent energy resources) in 2029 is higher than current record (14,809 MW in 2014 and 17,611 MW in 2029). Therefore, during low net load hours there will be no significant change compared to current operating conditions in terms of MW of thermal generation online, inertial response and frequency response available during generation trip events.

Significant increase can be seen in net load ramps compared to current experience. While the net load down ramps in 2029 are still largely defined by decreases in load at night, as is the case currently, the highest net load up ramps are defined by rapid solar production decline at sunset and simultaneous decline in wind production during evening load pick-up. Table 7 displays the maximum ramp-up and ramp-down in 2029 in the \$25/ton CO₂ scenario. Figure 7 shows wind and solar generation output and customer demand (load) on the day with the highest three hour net load ramp in 2029 from the \$25/ton CO₂ scenario.

Table 7: Maximum Ramp-up and Ramp-Down

Net Load	Maximum 60-min Ramp-up (MW/60Mins)	Maximum 60-min Ramp-down (MW/60Mins)	Maximum 180-min Ramp-up (MW/180Mins)	Maximum 180-min Ramp-down (MW/180Mins)
2011 Net Load (actual)	6,267	-6,124	16,058	-18,985
2012 Net Load (actual)	6,563	-7,019	14,997	-15,977
2013 Net Load (Jan-May) (actual)	6,247	-5,446	12,200	-14,373
2029 Net Load (modeled \$25/ton CO ₂ scenario)	11,074	-11,938	22,221	-22,560

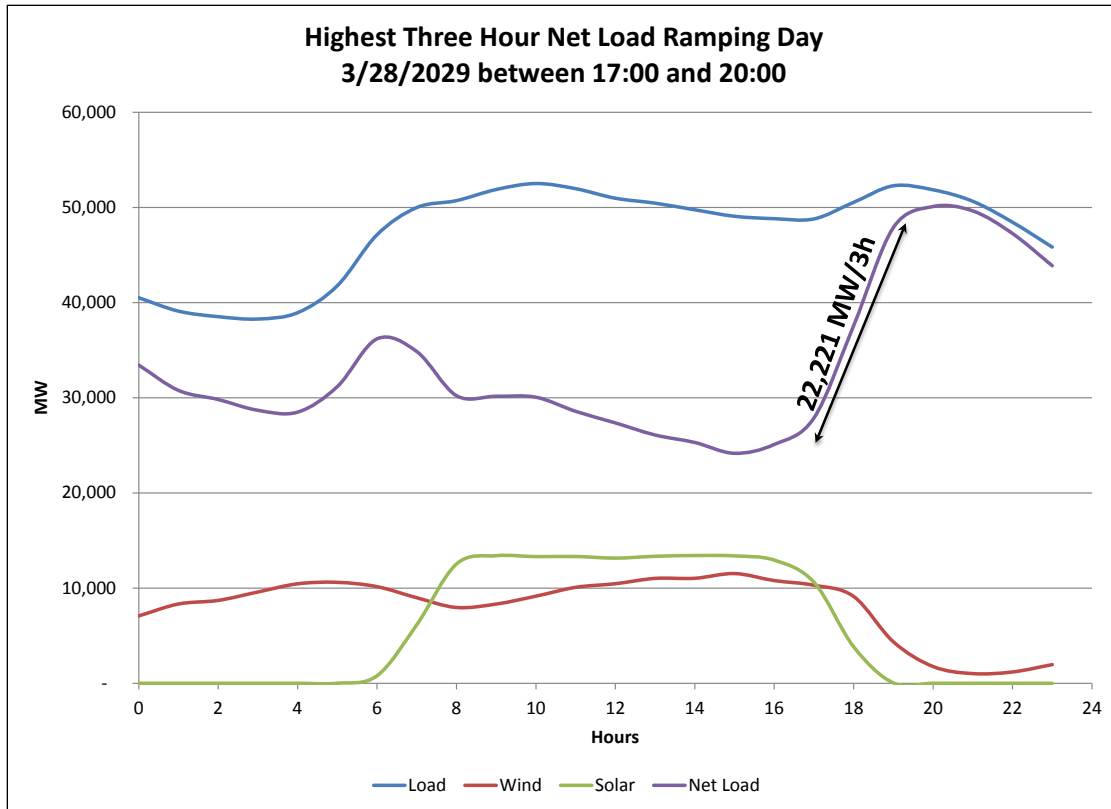


Figure 7: Highest Three Hour Net Load Ramping Day

The simulation model assumes perfect foresight and ensures that there is sufficient amount of thermal generation with sufficient ramping capability committed to follow such rapid net load ramps. In real time operation, however, accommodating the maximum ramps resulting from simultaneous solar and wind generation decline would be more challenging. At times, the existing and planned generation fleet will likely need to operate for more hours at lower minimum operating levels and provide more frequent starts, stops, and cycling over the operating day. It is important that market mechanisms are adopted so that the need for flexible generation (with short start-up times and high ramping capability) is reflected in real-time energy prices. Market mechanisms to include dispatchable load resources could also help to address flexibility needs. Enhancing wind and solar forecasting systems to provide more accurate wind and solar generation projections will become increasingly important. Regulation and Non-Spinning reserves will need to be increased to address increased intra-hour variability and uncertainty of power production from wind and solar. Tools available to system operators must be enhanced to include short-term (10-min, 30-min, 60-min, 180-min) net-load ramp forecasts and simultaneous assessment of real-time ramping capability of the committed thermal generation to assist operators in maintaining grid reliability.¹⁶

Though all solar capacity additions predicted by the model were utility-scale, it is likely that a significant portion of future solar generation capacity will be embedded in the distribution grid (e.g., rooftop solar and small scale utility solar connected at lower voltage levels). ERCOT does not currently have visibility of these resources. To produce accurate solar production forecasts, ERCOT would need to have information regarding the size and location of distributed solar installations. Additionally, to ensure grid

¹⁶ These findings are consistent with an assessment conducted by the North American Electric Reliability Corporation (NERC) and California ISO (CAISO), *Maintaining Bulk Power System Reliability While Integrating Variable Energy Resources*, November 2013. Available from http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC-CAISO_VG_Assessment_Final.pdf.

reliability, there would need to be increased consideration of operational activities on the distribution and transmission systems.¹⁷

Based on ERCOT's modeling, the majority of new renewable generation resource additions are anticipated to be solar. However, if instead ERCOT sees a large amount of wind resource capacity additions, then the reliability impacts may be more severe. Wind production in West Texas results in high renewable penetration during early morning hours, when load is lowest. An expansion in wind production, rather than solar, may result in lower net loads and significant reliability issues. If ERCOT cannot reliably operate the grid with these high renewable penetration levels, then production from these resources will be curtailed to maintain operational reliability. Should this occur, it would reduce production from renewable resources, leading to possible non-compliance with the proposed rule deadlines.

4. Impact on Transmission Infrastructure

As previously noted, ERCOT's analysis indicates that imposition of the constraints proposed in the Clean Power Plan will result in retirement of legacy base-load generation and development of new renewable generation resources. These changes to the ERCOT generation mix will likely require significant upgrades to the transmission infrastructure of the ERCOT system.

The retirement of a large amount of coal-fired and/or gas steam resource capacity in the ERCOT region would have a significant impact on the reliability of the transmission system. The transmission system is currently designed to reliably deliver power from existing generating resources to customer loads, with the existing legacy resources that are located near major load centers serving to relieve constraints and maintain grid reliability. Retirement of these resources would result in a loss of real and reactive power, potentially exceeding thermal transmission limitations and the ability to maintain stable transmission voltages while reliably moving power from distant resources to major load centers. A significant amount of transmission system improvements would likely be required to ensure transmission system reliability criteria are met even if a moderate amount of coal-fired and gas steam resources were to be displaced. If new natural gas combined cycle resources were to locate at or near retiring coal-fired and gas steam resources, the impact would be lessened.

In the ERCOT region, it takes at least five years for a new major transmission project to be planned, routed, approved and constructed. As such, in order for major transmission constraints to be addressed in a timely fashion, the need must be seen at least five years in advance. Given the competitiveness of the current ERCOT market, unit retirement decisions will likely be made with only the minimum required notification (currently 90 days). Reliability-must-run contracts may provide an avenue to maintain generation resources necessary to support grid reliability, but these make-whole contracts could incur significant market uplift costs, especially if they are needed for several years or if the contracted units require capital investments in order to maintain compliance with other environmental regulations.

The growing loads in the ERCOT urban centers are causing continued growth in customer demand and a resulting need for new transmission infrastructure. As the units that are at risk of retirement from the proposed rule are located near these load centers, future transmission needs would be increased or accelerated by the likely retirements. A new 345-kV transmission line is currently planned to be in place by 2018 to serve customers in the Houston region, at an estimated cost of more than \$590 million. Long-

¹⁷ These findings are consistent with an assessment conducted by the North American Electric Reliability Corporation (NERC) and California ISO (CAISO), *Maintaining Bulk Power System Reliability While Integrating Variable Energy Resources*, November 2013. Available from http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC-CAISO_VG_Assessment_Final.pdf.

term studies indicate a potential need for further upgrades in the mid-2020s.¹⁸ The retirement of generation resources within the Houston area prior to 2018 would likely result in grid reliability issues prior to completion of the proposed project. Retirement of generation after 2018 would accelerate the need for additional transmission from the long-term horizon (6-15 years) into the near-term horizon (1-6 years).

Similarly in the San Antonio and the Dallas-Fort Worth regions there are multiple new transmission projects that are being planned to serve existing load growth. At costs of hundreds of millions of dollars, the need for these and similar projects would be accelerated by retirement of legacy units in these regions.

Growth in renewable generation would also likely have a significant impact on transmission requirements. Although ERCOT did not estimate the costs of these transmission infrastructure improvements in this study, recent projects can be illustrative of the potential costs. In early 2014, the transmission upgrades needed to integrate the Texas Competitive Renewable Energy Zones (CREZ) were completed: more than 3,600 miles of new transmission lines constructed at a cost of \$6.9 billion dollars. The project took nearly a decade to complete. The CREZ project has contributed to Texas’ status as the largest wind power producer in the U.S.

While the CREZ transmission upgrades provide transmission capacity beyond current generation development, these new circuits will not provide sufficient capacity to reliably integrate the amount of renewables necessary to achieve the requirements of the proposed rule. Also, if the locations of new renewable generation do not coincide with CREZ infrastructure, further significant transmission improvements will be required. Given the need to increase the amount of renewable resources in order to achieve the proposed compliance requirements in the Clean Power Plan, it is likely that significant new transmission infrastructure would be required to connect new renewable resources.

5. Impact on Energy Costs

The model output included detailed cost information that can be used to characterize the impact of the Clean Power Plan on energy prices in ERCOT. This section discusses the cost impacts for the baseline, \$20/ton CO₂, and \$25/ton CO₂ scenarios. All cost figures are reported in nominal dollars, except capital costs, which are in real 2015 dollars.

Table 8: Locational Marginal Prices*

Locational Marginal Price	Baseline	CO ₂ \$20/ton	CO ₂ \$25/ton
2020 LMP (\$/MWh)	\$49.46	\$66.17	\$73.58
2029 LMP (\$/MWh)	\$72.02	\$81.13	\$84.28
2020 LMP % change from baseline	n/a	34	49
2029 LMP % change from baseline	n/a	13	17
2020 retail energy bill % change	n/a	14	20
2029 retail energy bill % change	n/a	5	7

*LMPs for the CO₂ limit scenario were not available at the time of completion of this report. They will be provided in the full report published in mid-December.

The inclusion of carbon prices resulted in higher average locational marginal prices (LMPs) compared to the baseline scenario, as shown in Table 8.¹⁹ In the \$20/ton carbon price scenario, the average LMP in ERCOT was \$66.17 in 2020 and \$81.13 in 2029 – 34% and 13% above the baseline scenario LMPs for those years, respectively. In the \$25/ton carbon price scenario, the average LMP was \$73.58 in 2020 and \$84.28 in 2030

¹⁸ See ERCOT’s 2013 *Report on Existing and Potential Electrical System Constraints and Needs*, available from

<http://www.ercot.com/content/news/presentations/2014/2013%20Constraints%20and%20Needs%20Report.pdf>.

¹⁹ LMPs for the CO₂ limit scenario were not available at the time of completion of this report. They will be provided in the full report published in mid-December.

– 49% and 17% above the baseline scenario estimates. As a general estimate, if wholesale power is 40% of the consumer bill, these increases in average LMPs would result in a retail energy price increase of 14 to 20% in 2020, and 5 to 7% in 2029. The increase in wholesale and consumer energy costs compared to the baseline decreases by 2029 due to the addition of new solar capacity, which has virtually no variable costs, and the accrual of energy efficiency savings. The costs of investments in energy efficiency are not estimated in this study. In their comments to the Public Utility Commission of Texas, EUMMOT estimated the cost of achieving the level of energy efficiency savings estimated by EPA at \$1.6 to \$2.9 billion per year in Texas.²⁰

The LMP reflects the variable cost associated with the generation resource on the margin. Though this measure provides an estimate of wholesale energy prices for consumers, the increase in production costs for generators would differ. The model results indicate that generators’ variable costs (which include fuel and emissions allowance costs) in 2020 will increase by 28 to 32% in the \$20/ton CO₂ \$25/ton CO₂ scenarios, respectively, compared to the baseline, as shown in Table 9. The variable costs of the carbon scenarios reflect the increased cost of natural gas generation, and the effects of energy efficiency and additional renewable generation. By 2029, these costs are 15 to 18% above the baseline for the two respective scenarios, as shown in Table 10. This increase is due in large part to the CO₂ emissions price, which in 2029 posed a cost of \$3.8 billion in the \$20/ton CO₂ scenario and \$4.4 billion in the \$25/ton CO₂ scenario, comprising 19% and 21% of total variable costs for the two respective scenarios.

Table 9: Fuel and Emissions Allowance Costs in 2020

Variable Costs	Baseline	CO ₂ Limit	CO ₂ \$20/ton	CO ₂ \$25/ton
Total Fuel and Emissions Allowance Costs (billions of dollars)	12.9	12.9	16.4	17.0
Total Fuel and Emissions Allowance Costs change from Baseline (%)	n/a	0	28	32
Average Fuel and Emissions Allowance Cost (\$/MWh)	30.54	31.82	40.80	41.65
Emissions Allowance Costs Only (billions of dollars)	0	0	3.5	4.1
Emissions Allowance Costs as percent of Total Fuel and Emissions Allowance Costs (%)	0	0	21	24

Table 10: Fuel and Emissions Allowance Costs in 2029

Variable Costs	Baseline	CO ₂ Limit	CO ₂ \$20/ton	CO ₂ \$25/ton
Total Fuel and Emissions Allowance Costs (billions of dollars)	17.7	16.8	20.4	20.9
Total Fuel and Emissions Allowance Costs change from Baseline (%)	n/a	-5	15	18
Average Fuel and Emissions Allowance Cost (\$/MWh)	37.07	36.60	44.28	45.49
Emissions Allowance Costs Only (billions of dollars)	0	0	3.8	4.4
Emissions Allowance Costs as percent of Total Fuel and Emissions Allowance Costs (%)	0	0	19	21

Note that the information in Table 8, Table 9 and Table 10 do not include the associated costs of building or upgrading transmission infrastructure, natural gas infrastructure upgrades, ancillary services procurement, energy efficiency investments, and potential Reliability-must-run contracts.

²⁰ Presentation by Jarrett E. Simon, Director Energy Efficiency, CenterPoint Energy. *PUCT Workshop Project 42636: Comments on Proposed EPA Rule Regarding Greenhouse Gas Emissions for Existing Generating Units*, August 15, 2014. Available from the Public Utility Commission of Texas, Docket 42636, Item 21.

Additionally, there will be capital costs for new generation resources built in both the baseline and carbon scenario cases. As Table 11 shows, the capital costs in the carbon scenarios are \$7 to \$11 billion higher in the carbon scenarios compared to the baseline, or an increase of 52 to 77%.

Table 11: Total Capital Cost Investments by 2029

Capital Costs	Baseline	CO ₂ Limit	CO ₂ \$20/ton	CO ₂ \$25/ton
Total Capital Cost (billions of 2015\$)	14	23	22	25
Capital Cost change from baseline (billions of 2015\$)	n/a	8	7	11
Capital Cost change from baseline (%)	n/a	59	52	77

Figure 8 displays the capital costs by fuel type. Though not directly reflected in LMPs, these costs will also ultimately be reflected in consumers' energy bills.

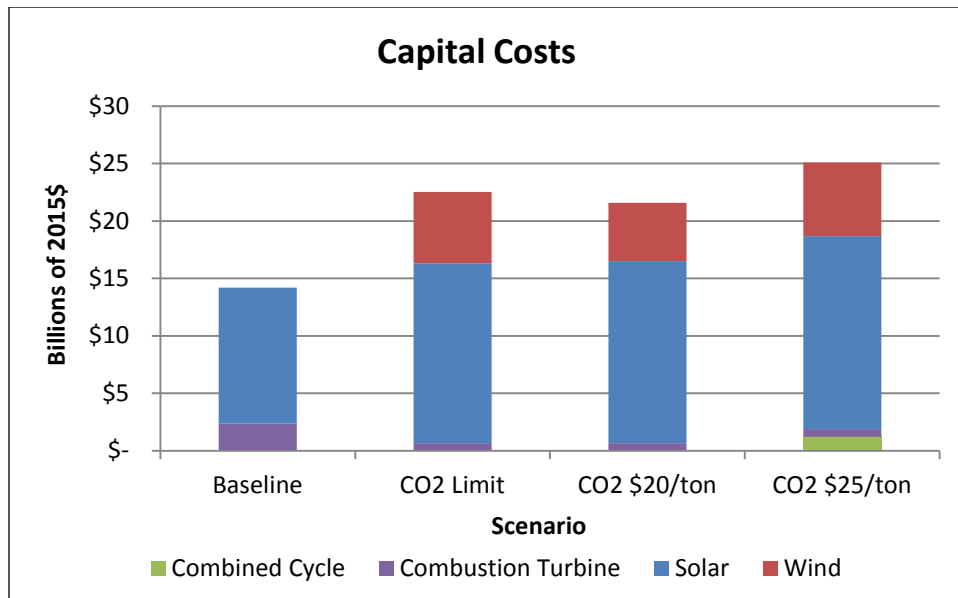


Figure 8: Capital Costs of New Capacity by Fuel Type

As previously described, the modeling results showed a decrease in the ERCOT reserve margin in the early years of the compliance timeframe. In a recently completed report prepared for the Public Utility Commission, the Brattle Group quantified the cost to consumers associated with periods of reduced reserve margins.²¹ These costs include a range of production costs, including the cost of emergency generation, the cost of utilizing interruptible customers, the costs of utilizing all of the available ancillary services, and the impact to consumers from firm load shedding, all of which increase at lower reserve margins. As an example, the retirement of 6,000 MW of generation capacity would be expected to reduce the system reserve margin by about 8%. Based on this report, if this change occurred when the system reserve margin was approximately 14%, the increased annual system costs at the resulting 6% reserve margin would be approximately \$800 million higher than would be expected prior to the regulatory impact.²²

Finally, it should be noted that ERCOT used the same natural gas price assumptions in all four scenarios. With the increased consumption of natural gas anticipated not only in ERCOT but nationally, natural gas

²¹ The Brattle Group. *Estimating the Economically Optimal Reserve Margin in ERCOT*, January, 2014. Available from http://interchange.puc.texas.gov/WebApp/Interchange/application/dbapps/filings/pgSearch_Results.asp?TXT_CNTR_NO=40000&TXT_ITEM_NO=649.

²² See Figure 22 of the Brattle Group report (page 48).

prices could increase beyond the levels anticipated in this modeling analysis. This would pose additional costs to consumers, which are not captured in this study.

6. Summary

Based on this analysis, it is evident that implementation of the proposed Clean Power Plan will have a significant impact on the planning and operation of the ERCOT grid. The proposed CO₂ emissions limitations will result in significant retirement of coal generation capacity, could result in transmission reliability issues due to the loss of fossil fuel-fired generation resources in and around major urban centers, and will strain ERCOT's ability to integrate new intermittent renewable generation resources. If the expected retirement of coal resources were to occur over a short period of time, reserve margins in the ERCOT region could reduce considerably, leading to increased risk of rotating outages as a last resort to maintain operating balance between customer demand and available generation. The need to maintain operational reliability (i.e., insufficient ramping capability) could require the curtailment of renewable generation resources. This would limit and/or delay the integration of renewable resources, leading to possible non-compliance with the proposed rule deadlines.

As noted previously, ERCOT supports the IRC proposal for inclusion of a reliability safety valve process in the context of the CO₂ rule, as well as the consideration of electric grid reliability during the development of State Implementation Plans. These proposals could help mitigate the potential reliability impacts of the Clean Power Plan.

The Clean Power Plan will also result in increased energy costs for consumers in the ERCOT region. Based on ERCOT's analysis, energy costs for consumers may increase by up to 20% in 2020, without accounting for the associated costs of transmission upgrades, natural gas supply infrastructure upgrades, procurement of additional ancillary services, energy efficiency investments, capital costs of new capacity, and other costs associated with the retirement or decreased operation of coal-fired capacity in ERCOT. Consideration of these factors would result in even higher energy costs for consumers.

ERCOT will issue the full report of this environmental regulatory impact study in mid-December 2014. The full report will include information about the impacts to ERCOT of several proposed or recently finalized environmental regulations, including MATS, CSAPR, the Regional Haze program, the 316(b) Cooling Water Intake Structures rule, and the coal ash rules. The report will also provide more details about the modeling analysis of the Clean Power Plan. As new information becomes available, ERCOT will continue to analyze the impacts of the Clean Power Plan, as well as other regulatory developments that may impact the ability to provide reliable electricity to consumers in Texas.

ATTACHMENT D

Summary of Travis Kavulla, Montana Public Service Commissioner

Sept. 9, 2014

State Perspectives: Questions Concerning EPA's Proposed Clean Power Plan

This testimony focuses on where the EPA's proposed carbon rule meets the practical realities of the power sector. In particular, I address the reliability impacts of the regulation and the generalizations that underlie the EPA's goal-setting process for states.

Despite "reliability" being a watchword in the conversation surrounding the EPA's regulation, no grid reliability analysis has been conducted in my region. No one is in a position to reach conclusions about the regulation's reliability implications for the Western grid. Moreover, such a study will not be completed by the October comment deadline.

The remainder of this testimony focuses on specific, on-the-ground examples where local realities diverge considerably from the generic assumptions that EPA uses to establish individual state goals. By applying a cookie-cutter formula to states, the EPA's "Best System of Emission Reduction" (BSER) is predicated on untrue generalizations not only about the upgrades available at power plants that emit carbon dioxide, but about the robustness of the electric grid, the nature of natural-gas generators' operations, and the prospects for increasing renewable energy and energy efficiency.

The power plants that generate electricity and the grid that moves electricity to and from are configured differently in each state and region. Montana and its neighbors rely on a weak grid and only a few generators to meet local consumer demand, exporting much of the rest of in-state electrical generation. Ironically, the EPA's state goal-setting process has the effect of punishing states in my region for being early adopters of pollution controls and for diversifying their fuel mix to include less carbon-intensive power plants. The proposed rule also swaps a local understanding of the possibilities and limitations of renewables and energy efficiency for sweeping assumptions about these things that are not sourced from state-specific experience.

The EPA's rapidly approaching October comment deadline must be extended to provide sufficient time for reliability analysis to be conducted, and many parts of the rule must be reworked considerably if state goals are to be founded on a realistic assessment of what is achievable in a state.

**Written Testimony of
Travis Kavulla
Montana Public Service Commissioner**

**Before the
Committee on Energy and Commerce
Subcommittee on Energy and Power
United States House of Representatives**

**Hearing on
State Perspectives: Questions Concerning EPA's Proposed Clean Power Plan
Sept. 9, 2014**

Chairman Whitfield, Ranking Member Rush, and members of the Committee, I am honored to be given the opportunity to offer my thoughts on the Environmental Protection Agency's (EPA's) proposed 111(d) regulation, which if adopted has the potential to reshape large parts of the utility industry. As a state utility commissioner, I am tasked with approving the consumer rates that will be necessary to pay for what the EPA is proposing.

My focus today is not on the underlying policy debate. The Clean Air Act confers on EPA the authority—and indeed requires the agency—to address the emission of carbon dioxide and other greenhouse gases that contribute to climate change. Rather, my concerns regard the approach EPA is taking in fulfilling this responsibility.

I will address first an issue that is overwhelmingly important, the reliability of the electric grid, before moving to a consideration of the specific assumptions the EPA has used to establish state goals. Here, my focus is not on what states may do to comply with the specific lbs/MWh number the EPA has spelled out for them; those conversations will unfold over the coming years. For now, in advance of the EPA's rapidly approaching October comment deadline on the proposed rule, it is crucially important to engage in a discussion about the basis—really, the lack thereof—for the state goals EPA has proposed.

But first, allow me to introduce myself to the subcommittee. I was elected to office in 2010, and represent approximately 200,000 constituents in the State of Montana. The district I represent spans 500 miles across the service territories of numerous electric utilities. In addition to my duties on Montana's Public Service Commission, I serve in a number of other capacities that touch upon this important topic. I am the co-chairman of the Northern Tier Transmission Group's steering committee, which establishes policy for the cooperative planning efforts of several large transmission owners in Montana, Idaho, Utah, Wyoming, and Oregon.

Additionally, I am a former Director and currently serve on the Member Advisory Committee of the Western Electricity Coordinating Council (WECC), the organization charged by NERC and FERC with adopting and enforcing reliability standards for the Western Interconnection that spans from California to Alberta. WECC also conducts transmission planning and reliability analyses that model the consequences of public policy proposals like the 111(d) rule. Finally, I serve on the Boards of Directors of the National Association of Regulatory Utility Commissioners and its research arm the National Regulatory Research Institute.

Reliability

Much of the conversation around the EPA's proposed rule has focused on the question of reliability. I will not speculate on the rule's reliability impacts, for the simple reason that no reliability analysis of the EPA's proposed "Best System of Emission Reduction" (BSER) has been conducted for the Western Interconnection, which encompasses 11 states, 2 Canadian provinces, and Mexico's Baja California. Transmission planners at WECC, which is responsible for adopting and enforcing reliability standards for this large slice of the continent, have told state regulators that they cannot accomplish such an analysis by the October comment deadline.

Other than WECC, few if any other organizations are in a position to conduct such an analysis. In any case, none have.

Many, including the EPA itself, have said that whatever else the proposed regulation accomplishes, it must keep the electric grid operating reliably. I agree. Absent a transmission modeling study that concludes that the BSER's Building Block approach would result in a system as reliable as the one we have today, it is inappropriate to claim that the EPA's BSER is adequately demonstrated.

EPA has modeled the outcome of the BSER assumptions using its Integrated Planning Model (IPM). It is important to understand what this model is and is not. The IPM does not and is not intended to model the operations of the transmission grid. Instead, the model focuses on whether in a particular region there are an adequate amount of electric supply resources to meet consumer demand. While this question of resource adequacy is essential to reliability, it is equally necessary to understand whether the resources that exist in a particular region can be delivered to the consumer location of demand. Many of the most critical resources that serve large pockets of consumer demand are located in transmission-congested areas. If this transmission congestion is not incorporated into a model—and, again, IPM does not—then that model cannot reach meaningful conclusions about system reliability. In other words, the way IPM has drawn the regions in its hub-and-spoke representation of the grid do not capture the significant complexity of grid operations *within* the given region. Additionally, IPM uses an old-world definition of regions that does not accurately represent the present realities of how the transmission grid has been divided into Regional Transmission Organizations (RTOs).

Even assuming that the BSER is otherwise a feasible metric for accomplishing the EPA's goal of reducing carbon dioxide emissions, it must be subjected to transmission modeling. This is

not possible before the October comment deadline. For that reason alone, the deadline should be extended.

The EPA's Building Block Approach to Establishing State Goals for Carbon Reduction

As the subcommittee is aware, the EPA's proposed regulation establishes individualized state mandates based on what EPA assumes are feasible accomplishments in four areas: efficiency improvements at power plants, the increased operation of existing natural-gas combined cycle plants, the construction of additional renewable generators powered by wind and solar, and increased energy efficiency on the part of consumers which reduces overall demand. These four Building Blocks are, in general, already being used by states to varying degrees for a variety of purposes, including carbon reduction. Yet the EPA essentially ignores the details of a state's situation, and instead applies a cookie-cutter formula that uses sweeping regional or national assumptions about the degree to which each individual Building Block is achievable. The result is that any given state goal is predicated on a so-called Best System of Emission Reduction that ignores the realities of commercial relationships, the way in which generators are dispatched, the footprint of regional markets, the status of individual power plants, the robustness of the electric and natural gas transmission system, and potential energy efficiency savings on the ground. Even though the state goal-setting process of the BSER is flawed, some states nonetheless would be able to achieve the goal by other means (for example, by simply shutting down coal-fired generators, and not attempting to implement the Rube Goldberg device the Building Blocks represent). But for other states, the application of the BSER's Building Blocks to the state's electric profile results in a goal that is unrealistic via the BSER or by other means short of a complete overhaul of its energy supply mix.

Building Block 1: Efficiency Improvements at Coal-Fired Power Plants

The EPA assumes carbon-emitting power plants that are subject to the rule would be able to achieve a 6% efficiency improvement (i.e., 6% less fuel would need to be burned to obtain the same amount of electricity). This assumption is applied uniformly across the country, regardless of whether a given power plant has or has not made these upgrades already. Ironically, the many power plants that have already made such upgrades are penalized by the proposed rule because it is assumed that a further 6% reduction can be made against the 2012 baseline data the EPA uses, in which the results of efficiency improvements are already embedded.

A specific example of this is the Big Stone plant located in South Dakota. Co-owned by Otter Tail Power, Montana-Dakota Utilities, and NorthWestern Corporation, it provides energy to consumers throughout the Great Plains, including to the MDU customers I represent in Eastern Montana. Big Stone's owners have already made most of the heat-rate upgrades Building Block 1 contemplates. Additional efficiency improvements capable of obtaining another 6% savings are simply unavailable, and the few improvements that could be made are simply not economical. Also, in order to comply with another EPA rule, the Regional Haze Rule for South Dakota, Big Stone is in the process of installing upgrading its Air Quality Control System (AQCS), at a cost of nearly \$400 million. In order to control the emissions that cause haze, however, 8 megawatts of the plant's production will have to be dedicated to running the pollution control equipment. This "parasitic load" actually means that more tons of carbon emissions per megawatt-hour of net production will be produced by the plant, but in service of controlling haze. In other words, to comply with one EPA rule endangers Big Stone's ability to obtain the efficiency upgrades that are the assumed possible by the proposed EPA rule.

Montana's 2,100-megawatt Colstrip facility—the second-largest coal-fired power plant in the West—is in the same situation. That facility's operator, PPL-Montana, has made several efficiency improvements over the last decade that have made the plant operate about 5% more efficiently. These upgrades include an approximately 3-4% efficiency improvement resulting from using a new blade design in the turbine rotors, allowing the plant to use the same amount of steam flow to generate more electricity; a less than 1% efficiency gain from boiler upgrades; and a less than 0.5% efficiency upgrade resulting from cooling tower and fan improvements. There are not many other examples of additional projects that could be undertaken to result in efficiency improvements. Those that would work in certain parts of the country—for instance, drying moisture out of coal to improve the efficiency of combustion—will not work for Colstrip, because demineralized Powder River Basin coal becomes very combustible. Experiments at Colstrip with this approach have resulted in spontaneous combustion events. PPL-Montana already has a strong incentive to pursue efficiency upgrades that reduce cost and emissions alike, and at Colstrip most of those upgrades have already occurred. Only 1-2% efficiency gains remain on the table for Colstrip, yet in setting Montana's goal, the proposed rule assumes that 6% efficiency improvements are available. This is simply not true.

If EPA continues to use Building Block 1 to establish state goals, it should incorporate plant-specific data and not use a generic assumption that does not reflect the present status of individual plants. The agency must give credit to plants that have already made upgrades, and it should not punish states for heat-rate degrades that have resulted from installing pollution control equipment necessary under other air-quality rules.

Building Block 2: Increased Natural Gas Dispatch

Much of the attention paid to the BSER appears to have focused Building Block 2, questioning whether the nation's gas infrastructure is robust enough to support this Building Block's assumption that natural gas combined cycle combustion turbine (CCCT) plants can run consistently at a 70% capacity factor. I share this concern, but would like to focus on another specific example from my region where the EPA's assumptions do not comport with the realities on the ground.

Carbon savings associated with Building Block 2 occur in the EPA's assumptions because for every megawatt-hour of new generation from a CCCT, there is assumed to be a megawatt-hour less of generation from a more carbon-intensive generating unit. It appears that for a state plan to be compliant with the EPA's proposed rule, it would somehow need to demonstrate this offsetting relationship. Yet there are practical barriers that make this one-for-one exchange difficult or impossible.

The Big Stone plant, referred to above in relation to Building Block 1, is again an instructive example. The EPA assumes that this facility would be substantially replaced with natural-gas fired electricity generated at the Deer Creek Generating Station, which under Building Block 2's assumption would run at 70% capacity. These are the only two fossil units in South Dakota, and they serve customers in that state as well as North Dakota, Minnesota, and Montana.

There are several flaws with this assumption. First, the dispatch of these generating units is orchestrated by two separate operators. Although the EPA appears to assume that their operation is seamlessly interrelated, that is simply not the case. Deer Creek is dispatched through the region's Integrated System (IS) jointly operated by Basin Electric Power Cooperative (Basin)

and the Western Area Power Administration (WAPA); in 2016, it is planned that WAPA and Basin will participate in the Southwest Power Pool (SPP). Meanwhile the Big Stone plant operates within the Midcontinent Independent System Operator (MISO), which dispatches the share of power generated at the plant for MDU's customers, including those in Montana. IS/SPP and MISO do not share a dispatch signal that would allow one plant's increased operations to result in the lower dispatch of a plant operating in a different market. To analogize, it would be like suggesting that an apple bought in a supermarket on one side of town means one less will be sold at the store at the other side of town. There may be some interrelation between the two electric markets in question here, but it is not controllable absent a reorganization of the way the two markets interact, which is no easy matter. EPA appears to assume, in Building Block 2, that simply because two power plants are located in the same state, they must have a strong relationship with one another. In some states, this would be true. In South Dakota, in Montana, elsewhere, it is not true.

Additionally, these two power plants—Big Stone and Deer Creek—were built to their particular size and in their particular location, to serve the needs of their utilities' customer bases, not those of other utilities. Each of the various owners of each of these plants own firm transmission rights from these units to their retail loads; naturally, they do not own transmission rights originating at a plant they do not own, to their customers.

As a practical matter, the reduction that EPA assumes relative to Big Stone would result in the plant operating at 23% of capacity. Its minimum run level is 40%, meaning that the plant would either be required to be shut down or not run for a substantial period of the year (with an unknown impact on reliability). As noted above in my comments regarding Building Block 1, this is a plant that is at this very moment undergoing an expensive, \$400 million upgrade to

comply with other environmental rules; any “Best System of Emission Reduction” that causes its removal from the supply pool is not worth the name. Meanwhile, Basin designed Deer Creek, which became operational in 2012, to run 12-16 hours per day for five days a week; in other words, it was intended to operate a little less than half of the time, not 70% of the time. One of the reasons it was designed in this way is to integrate Basin’s substantial and growing portfolio of wind energy, which is abundant in this part of the nation. Deer Creek needs to have the capability to dispatch up when the wind suddenly does not blow, and need to be able to dispatch down when the wind picks up. Operating at a high capacity factor, 70%, would not allow the kind of ramping that is essential to Deer Creek’s purpose. It is yet another irony that operating natural gas plants the way Building Block 2 suggests could hamper those units’ ability to accommodate carbon-free wind energy. Utilities have built CCCTs in order to be on call to serve peak demand and to integrate variable energy resources like wind and solar. Yet the EPA rule essentially punishes consumers whose utilities have increased the diversity of their fuel mix by adding a CCCT, because any CCCT that operates at a lower-than-70% capacity factor is, for the purpose of setting a more onerous state goal, assumed to be able to dispatch up to that level on a 24-7 basis.

Building Block 2 simply does not acknowledge the realities of the power sector. EPA should make accommodations for states where no market relationship exists between a CCCT and the coal-fired generating unit the BSER assumes it will offset.¹ It should also assume a lower average dispatch for the many CCCTs whose purpose is not just base-load power, but serving peak needs and integrating weather-dependent renewables.

¹ Enacting the assumptions in Building Block 2, with this condition, would nonetheless require grid operators to dispatch higher-cost plants before lower-cost plants, rearranging what has traditionally been the straightforward practice of dispatching lower-cost units until the system demand is met. This is possible by adding a carbon price to the bid price of a coal plant within a market, and while disadvantageous to consumers, it is nonetheless possible. Building Block 2 in its current form is not possible.

Building Block 3: Increased Renewable Energy

Renewable energy has great promise in Montana and neighboring states, but the ability to construct new wind energy parks is limited by the constraints of the transmission system to send the energy to more populous areas where demand is concentrated, and by the ability of the rest of the generating fleet and the grid to reliably integrate weather-dependent renewable energy which may or may not be generated as needed. These are not intractable problems, but it is clear that the EPA rule has not thoroughly considered them—certainly not on the state-to-state basis that is necessary for the BSER to be adequately demonstrated.

As a preliminary matter, the EPA rule is vague and even self-contradicting on the question of which state should get credit for renewables. Should it be the state where the renewable generator is located, or another state where consumers of the energy might reside? Montana's Colstrip facility is mostly dedicated to serving out-of-state consumers over a long-distance, 500-kilovolt transmission line. Nonetheless, Montana under the EPA's proposed rule is assessed all of the carbon emissions associated with the facility. If this remains the case in the EPA rule, so too must it be clear the Montana-based renewables would count against the carbon footprint of this facility. Without this provision, Montana would not be able to use Building Block 3 as a step toward complying with the state's goal.

Second, the EPA has established the regional targets of Building Block 3 using an erroneous calculation. The EPA has reasoned that each state in a given region—"the West" is one, very large region in the rule—is capable of meeting a renewable energy target that is the average of the Renewable Energy Standards (RES) of the states in that region. For purposes of deriving this average, EPA has said that Montana has a 15% RES. This is misleading. Montana's

RES, like some other states', only applies to certain actors—namely, only to investor-owned utilities and certain small competitive suppliers serving Montana customers. It does *not* apply to consumer-owned utilities, to public power projects, or to generators owned by out-of-state utilities. In effect, Montana has required new renewable energy resources to constitute far less than 15% of the total generating mix. It is unclear what a true average of state requirements would look like, but it would certainly reduce the 21% regional renewable energy target for the West in Building Block 3, perhaps substantially.

There is unquestionably a bounty of wind resources in Montana. The state has the potential to develop more renewable generation than even the EPA's Building Block 3 imagines. But the ability to develop those resources is severely limited by the nature of the transmission grid. WECC has previously modeled scenarios where large amounts of "remote renewables" are located in Montana and Wyoming to serve out-of-state consumers. In those studies, the path limits of the transmission corridors from Montana to the Northwest were routinely (almost half of the time) pushed to the limit, and energy from renewables was forced to be "dumped"—generated, but not able to be transmitted to the customers who need it. One WECC study warned²:

The path rating for Path 8 [the Montana to Pacific Northwest corridor] is currently highly dependent on remedial action schemes that are directly linked with the coal-fired and hydro generation in Montana. There are inertial concerns in the area. The local balancing authorities have advised caution when running studies that dispatch renewable generation before coal-fired and hydro generation. In reality, the rating on Path 8 may have to be decreased when these conventional resources are backed down, or turned off completely.

Building Block 3 calls for less renewable energy than was modeled in those reliability analyses. However, this and other studies have made clear that there are reliability concerns associated

² WECC, "2022 Resource Options," (July 25, 2013), p. 51.

with adding renewables in Montana without significant transmission upgrades, which for reasons from siting to finance have been very difficult to come by. Adding capacity to new lines is on a limited basis possible, but it is expensive and these cost assumptions are not discussed in the EPA's proposed rule. On the other hand, if the construction of a new line was necessary to implement Building Block 3, it is not at all certain that this would be possible in time to meet EPA's goals.

Additionally, like for Building Block 2, the EPA assumes that renewable energy and coal-fired energy will be dispatched in an offsetting manner. This requires certain assumptions about the flexibility of coal plants that are unreasonable. Coal plants typically are not designed to cycle quickly to integrate renewables; they are meant to be run relatively flat, ramping up and down over longer periods of time. Even the certain coal units that are today being dispatched more quickly are showing more carbon-intensive heat rates; they emit more carbon per megawatt-hour for the energy they do produce, and it appears that effect has not been captured in the EPA's proposed rule. In Montana, as the quotation from WECC above notes, the high voltage transmission line that runs from Colstrip to points hundreds of miles west is dependent on the inertia this very large coal-fired plant provides. If that facility does not run, then the line may not be reliable to operate. Specific instances of transmission vulnerability, like this one, have been entirely overlooked in the EPA's proposed rule.

Like for Building Blocks 1 and 2, the EPA must not fall through the trapdoor of generalization when it comes to imposing Building Block 3 for the creation of a state goal. Montana's example in this regard is telling.

Building Block 4: Increased Energy Efficiency

The EPA's energy efficiency targets are, unlike renewables, not even predicated on a regional average—but a national average, which supposes that it is possible to achieve an annual 1.5% savings through energy efficiency measures. Each state's utility commission of which I am aware has evaluated the potential energy savings available to the utilities it regulates, and the possibilities depend on many variables, from climate of the region, to the hours of daylight at the particular latitude, to the mix of consumers (industrial versus residential) served by the utilities. That is why each state has a utility commission, and why it makes sense to house this kind of decision-making at the state or local level, and not in a federal agency. Unfortunately, Building Block 4 is perhaps the banner example of the BSE's supposition of an arbitrary target that lacks meaningful substantiation in the real world. The Public Service Commission in Montana (and the comparable agency in many other states) already obligates the utilities that it regulates to acquire all cost-effective energy efficiency available to them. The EPA's rule supposes that there is a substantial amount beyond this available for the taking. This assumption is only thinly evidenced in the EPA's rule.

Additionally, the practical implementation of Building Block 4 runs into the same problem that characterizes Building Blocks 2 and 3: a disconnect between the demand in a state that energy efficiency would apply to, and the generating resources of that state. In the case of Montana, I have observed above that the carbon-emitting units subject to the 111(d) proposed regulation mostly are dedicated to serving out-of-state consumers. Yet Building Block 4 assumes a reduction in demand on the part of Montana consumers, many of whom have nothing to do with the operation of the coal-fired units in question. There is no direct, causal link between a Montanan's energy savings, and the amount of generation output at the Colstrip facility that constitutes the vast majority of Montana's carbon emissions. The EPA rule is vague about how a

state in Montana's position could implement Building Block 4 in a way that the EPA considers compliant, i.e., that shows an offsetting effect between energy efficiency programs and coal-fired generating units.

Additionally, it is unclear how a state plan that includes energy efficiency would be enforceable. Presumably such a plan would attempt to identify specific programs that would lead to energy efficiency gains, but the points of compliance would be possibly thousands of consumers performing small, discrete actions, and not typical of other environmental regulations that require a single plant operator to install pollution control technologies. The Montana PSC's experience with measuring energy efficiency savings is that it relies heavily on assumptions (what was saved against a hypothetical base case). Demonstrating compliance could prove difficult and contentious.

Finally, this Building Block, like others, ironically punishes early adopters of energy efficiency. The Building Block, as applied to states, ramps up at a 0.2% level annually to a 1.5% annual energy savings. So a state that is already aggressive in its energy efficiency programs, and which presumably has invested in more and more costly energy efficiency investments over time, may be starting out at around a 1.5% savings, which the Building Block holds the state to throughout the compliance timeframe. Meanwhile, a state with a modest energy efficiency portfolio may start with, say, a 0.5% annual savings, and it would take five years for the Building Block to ramp up the savings to 1.5%. In short, the proposed rule is more punitive on early adopters and those who have already achieved many energy efficiency gains, than those who have not.

If it continues to use Building Block 4 as part of the BSER, the EPA should only consider the possible energy efficiency savings of consumers who have a direct relationship with the

dispatch of a coal-fired generating unit. Additionally, the EPA should defer to states on identifying the amount of energy efficiency savings that are cost-effective given the profound differences that exist between states in relation to this question.

Other concerns

Basing an entire regulation on a single year of data (in this case, 2012) is problematic for two reasons. First, any given year may be unusual compared to what is typical, and in the Northwest, a good water year and low gas prices caused coal plants to run less often in that year than they otherwise would have. A multi-year average would better represent what is typical. Second, although much of the data EPA collects is subjected to quality assurance and quality control, there are still a number of different methodologies for measuring the carbon intensity of a power plant. The rule's underlying assumption is that reductions will be measurable and real compared to a baseline year's data which is similarly assumed to be measurable and real. This hopeful assumption may not be accurate.

It is clear that the EPA proposal requires major changes, if not a complete overhaul. Even if the EPA did not make changes to deal with the numerous criticisms of matters that the EPA has tentatively settled upon, there are numerous points in the proposed rule where the EPA itself has merely offered a spectrum of potential directions and requested comment about which option the EPA should select. The draft rule is not fully baked, meaning EPA could arrive at a final rule in which states will be seeing key elements of the rule (and the potential interaction between key elements) for the first time. There needs to be another substantial round of comment, with the possibility of further changes, and not a final, immovable rule in 2015.

I have appreciated the opportunity to express these views on the record, and am happy to answer questions about them. I leave you with one final thought: The much-heralded flexibility that the proposed EPA rule provides to states is a meaningless concept, if the underlying goal—a number which is inflexible—has been calculated using generic assumptions that are misleading or false when applied to the facts of a specific state, in a specific part of the transmission grid. The goals established for states must be premised on reasonable, adequately demonstrated measures. The EPA's rule has much progress to make in that regard.

ATTACHMENT E

**Testimony before the Energy and Power Subcommittee
of the House Energy and Commerce Committee
Texas Public Utility Commissioner Kenneth W. Anderson, Jr.**

Executive Summary

Texas is the only state that has a physical presence within all three electric interconnections. In Texas, 85% of the electricity is consumed within the Electric Reliability Council of Texas power region (ERCOT), a non-FERC jurisdictional restructured, competitive, energy-only wholesale and largely competition retail market (the Texas ERCOT market). ERCOT's electric grid, which covers approximately 75% of the state, is an island with only limited direct current ties to the eastern and western interconnections. The remaining 15% of electric consumption takes place in areas outside of ERCOT served by cooperatives and vertically integrated, investor-owned utilities whose rates and terms of retail service are regulated by the Public Utility Commission of Texas (PUCT). All of the Texas utilities (public or private) located in the eastern interconnection are members of the Southwest Power Pool or the Midcontinent Independent System Operator.

Texas is disproportionately affected by the United States Environmental Protection Agency's (EPA) proposed Section 111(d) Clean Power Plan rule. The rule as proposed raises substantial questions around fairness (EPA proposes that Texas should account for 18% to 25% of national CO₂ reduction), cost, implementation alternatives, system reliability and whether compliance is even physically possible, at least within the timelines proposed by the EPA. The EPA compliance building blocks actually work at cross purpose, at least in Texas, largely because they do not give any credit for substantial improvements made since 2001, much less 2005, or recognize how security constrained economic dispatch works in organized wholesale power markets. For example, EPA's "building block" 1 (6% across the board improvement in

coal-fired heat rate) assumes that efficiency improvements are still available. The Texas ERCOT competitive market has already forced coal-fired generators to adopt state of the art technologies available to improve thermal efficiencies in order to compete effectively. Another example: “building blocks” 2 (70% capacity factor of natural gas combined-cycle generation) and 3 (increase in non-hydroelectric renewable energy megawatt hours (MWh) to 20% of the state’s total energy produced) act counter to each other in Texas, making “building block” 1 impossible to achieve, and simultaneously worsening emissions of not only CO₂, but other harmful pollutants. “Building block” 3 assumes that the Texas renewable energy production can increase to a level above the minimum load in the Texas ERCOT market. Putting aside the timing, cost, and reliability issues, relying on this compliance alternative will likely shut down all other generation during certain times of the day, including nuclear. This creates a paradox. Texas cannot achieve both a 70% capacity factor for gas combined cycle plants and 20% renewable energy production without increasing CO₂ emissions. This occurs, in part, because the 2012 energy baseline year selected by the EPA does not give Texas any credit for the already dramatic increase in Texas wind generation that delivered 35.917 million MWh (16.24% of this nation’s non-hydro renewable generation) in 2013.¹

¹ United States Energy Information Administration, *Electric Power Monthly*, Data for June 2014, released August 25, 2014, Table 1.1.A Net Generation from Renewable Sources: Total (All Sectors), 2004 – June 2014. American Wind Energy Association, *Wind Energy Generation by State, 2013*, <http://www.awea.org/generationrecords>. For 2013, conventional hydroelectric is shown to be 269.136 million MWh. However the industrial sector used 3.4 million MWh of hydroelectric power generated in 2013, see US EIA note 4, at 94. Therefore, US renewable energy generated in 2013 less hydroelectric power in the Electric Power Sector was $487 - 269.136 + 3.4 = 221.264$ million MWh. $35.937/221.264 = 16.24\%$ of US electric power sector renewable generation not including hydroelectric.

EPA's Clean Power Plant Rule Applied to Texas

In early June of 2014 the EPA proposed a rule for reducing carbon dioxide (CO₂) emissions from existing power plants under Section 111(d) the Clean Air Act. As proposed, the rule requires each state to reduce its overall CO₂ rate of emission from existing power plants to a state-specific level, with an interim target to be reached by 2020 and the final rate to be achieved by 2030. The standard is set in pounds per MWh. The state standards vary dramatically, with Texas' standard set at a 2020 level of 853 lbs/MWh which must decline to 791 lbs/MWh by 2030. It is worth noting that both the interim and final standards applied to Texas is substantially lower than the CO₂ per MWh emission level required by the EPA to be achieved by new coal or gas power plants under Section 111(b) of the Clean Air Act. EPA's proposal would require Texas to account for somewhere between 18 to 25% of the country's total CO₂ reductions.

In the proposed Clean Power Plan rule the EPA set out four "building blocks" as the Best System of Emissions Reductions (BSER) to be used by the States in their State Implementation Plans (SIP) to reduce overall CO₂ emissions from existing power plants. As applied to Texas, the four building blocks are: (1) across the board coal plant heat rate improvements of approximately 6% (Block 1), (2) re-dispatch of existing coal plants so that gas combined cycle plants achieve roughly a 70% utilization rate or capacity factor² (Block 2), (3) an increase renewable energy produced (primarily from wind) of approximately 150% based upon Texas' 2012 energy output (Block 3), and (4) a substantial increase in energy efficiency programs (Block 4).

²By comparison, based solely on economic dispatch, gas plants, including both combined cycle and combustion turbines, produced 40.5% of all of the energy in ERCOT in 2013.

BSER Block 1: The Texas ERCOT Market has already achieved substantial improvements in efficiency

The improvements offered by Block 1 may be illusory. The EPA's proposed rule assumes that substantial thermal efficiencies can still be obtained from coal plants in Texas. However, at least within the ERCOT interconnection, there likely is little room for improvement in Block 1's heat rate improvement goal because much of the assumed efficiencies have already been implemented by coal-fired generation because of the competitive market.

ERCOT's energy market design has achieved this result by eliminating older, less efficient, and therefore less competitive generating facilities. Since 2002, over 13,000 megawatts (MW) of old thermal generation plants have been retired. Owners of generation are forced to make upgrades to their existing generating facilities to improve their thermal efficiencies so that they can remain competitive. If they are unable or unwilling to do so, they are driven from the market. Historically, new more efficient (and cleaner) units have stepped in to replace the older units. ERCOT's competitive market has in effect, already been implementing Block 1 for over a decade. By using 2012 as the base year, Texas gets no credit for having already achieved a significant amount of EPA's Block 1 goals.

The Paradoxes of Blocks 2 & 3

Within ERCOT, nuclear and coal-fired power plants provide base load generation and are most efficient (and with respect to coal plants, cleaner environmentally) when operating at or near 100% of capacity. ERCOT's nuclear generation fleet (in excess of 5,200 MW) was not designed for load following and therefore has very limited ramping capability. The Texas nuclear units operate most efficiently at 100% of capacity. Among other issues, operating a

nuclear facility at lower efficiency means that the plant creates more spent nuclear fuel per megawatt hour of electricity production. Coal (as well as most gas-fired) generation also operates most efficiently at or near 100% capacity. While a base load coal facility has more ramping capability than a nuclear facility, emissions of CO₂, as well as other emissions that actually are harmful to life such as NO_x and SO₂, increase substantially when ramping up or down or otherwise operating at less than 100% of capacity.

Figures 1 and 2 below illustrate seasonal load profiles experienced in Texas. Figure 1 is a typical August day in Texas. The ERCOT load almost doubles a summer day, increasing from about 36,000 MW to over 68,000 MW. This increase occurs over a 12 hour period. Figure 2 is a typical spring or fall day and shows how low the load in ERCOT typically can dip in the spring or fall. Texas must have a balanced diversified generation mix in order to be able to start up generation facilities as load climbs, and then be able to ramp them down as load declines.

Figure 1: Typical Summer Load Profile

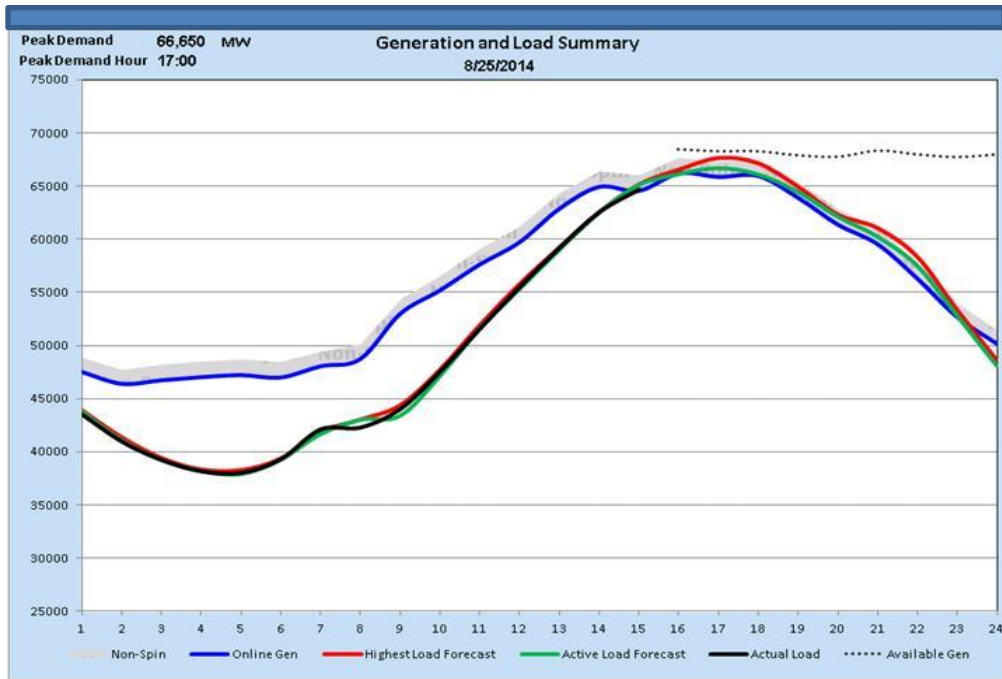
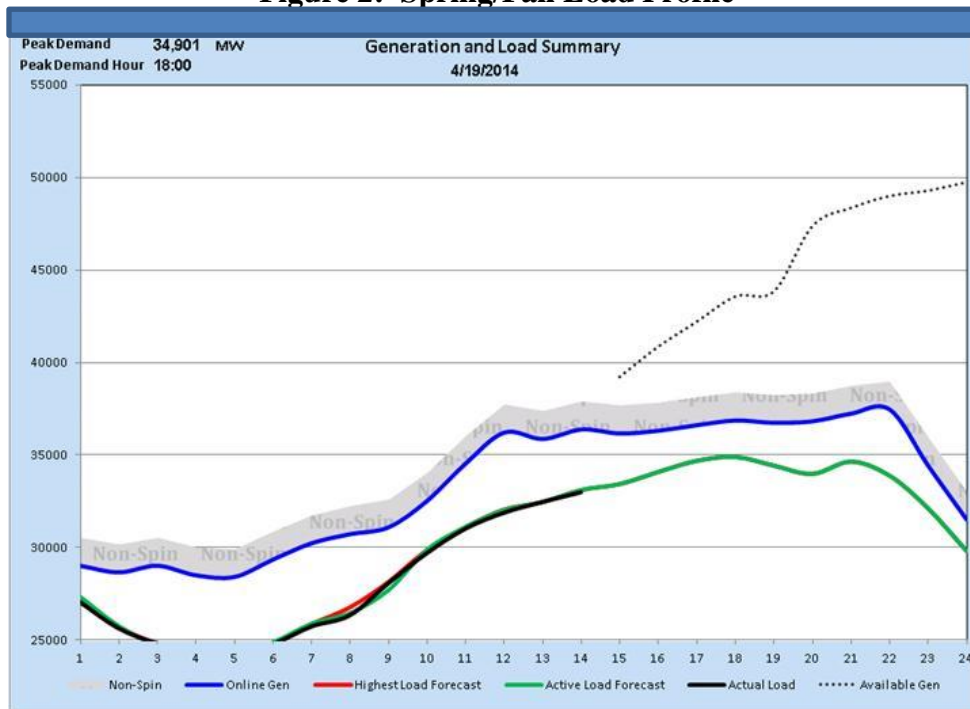


Figure 2: Spring/Fall Load Profile



While Figure 1 shows the 30,000 MW swings that the diversified ERCOT generation fleet must be able to handle in the summer, Figure 2 demonstrates a different problem that can

occur with too much renewable generation. Between 3:00 a.m. and 6:00 a.m. electricity consumption can drop below 25,000 MW. ERCOT already has experienced days in which wind has provided as much as 38.4%³ of the generation on the system. If Texas were to use Block 2 in any SIP in an attempt to comply with EPA's proposed Clean Power Plan, both practical as well as perverse difficulties would result. Wind turbines in Texas typically have a much higher capacity factor during spring and fall months. During the spring and fall a 20% renewable energy goal as proposed by the EPA under Block 3 could put more renewable generation on the grid than there is existing load. Consequently, during the early morning hours ERCOT would have to both curtail a substantial amount of the wind and back or shutdown much of the nuclear fleet and all other thermal generation, simultaneously reducing the effectiveness of both Block 2 and Block 3. As previously noted, nuclear generators operate most efficiently at or near 100% capacity. The practical problem is that large nuclear generating units are not designed to ramp up and down quickly or easily. The result of too much wind on the system would be that either the nuclear plants would bid negative prices in order to remain on the system, which would impair the financial viability of all on-line generation including the wind farms (particularly if the production tax credit is not renewed, because it enables wind farms to bid negative prices and still earn money) or the nuclear plant would have to shut down, which takes time and presents another Clean Power Plan rule compliance problem. ERCOT's nuclear plants are pressurized water reactors that are not designed for load following. After shutting down to the condition of hot standby, it takes about 12 hours for large nuclear generating units to start and return to full service. During that period, as wind declines, as it inevitably would (see Figure 3 below), the

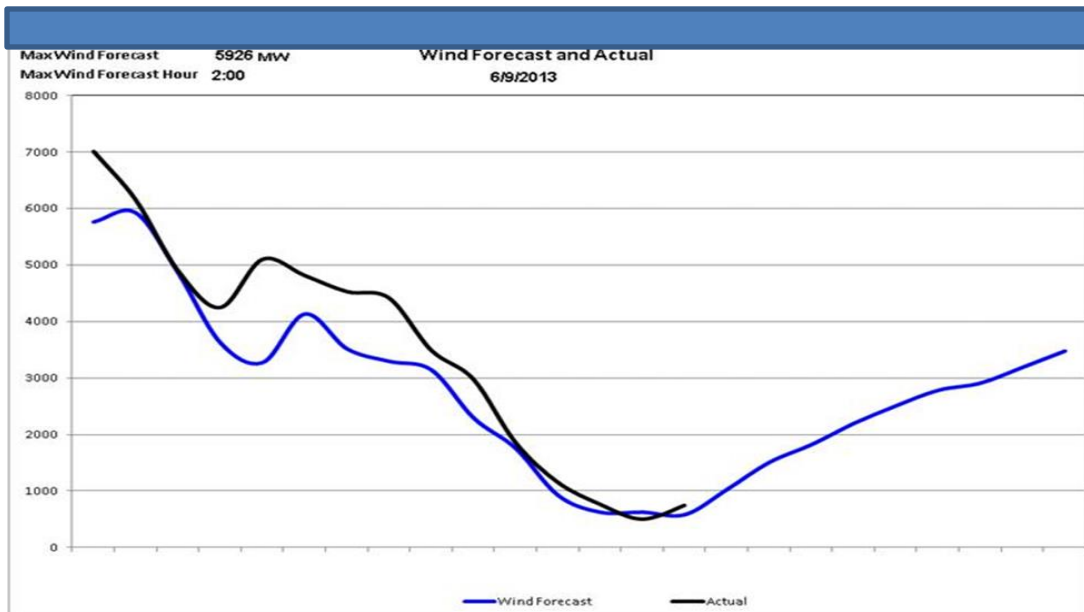
³ ERCOT News release, *Wind generation output in ERCOT tops 10,000 MW, breaks record*, reporting two records broken. On March 26, 2014 instantaneous output reached 10,296 MW at 8:48 p.m. (nearly 29% of total system load), and on March 27, 2014 at 3:19 a.m. when 9,868 MW served a record 38.43% of the 25,677 MW system-wide demand.

gap would have to be filled by CO₂ emitting resources such as gas-fired combined cycle or combustion turbine units; presumably an outcome that EPA would prefer not occur.

Like nuclear units, base load coal-fired generation units operate most efficiently when they are at or near 100% capacity. Too much renewable energy could cause them to operate at less than peak efficiency and result in more CO₂ and other actually harmful pollutants being emitted.

But Blocks 2 and 3 yield a paradox as well. In a diversified, efficient market, Blocks 2 and 3 work at cross purposes. Figures 3 and 4 show the high variability of wind.

Figure 3: 93% Drop in Wind Production in 12 Hours

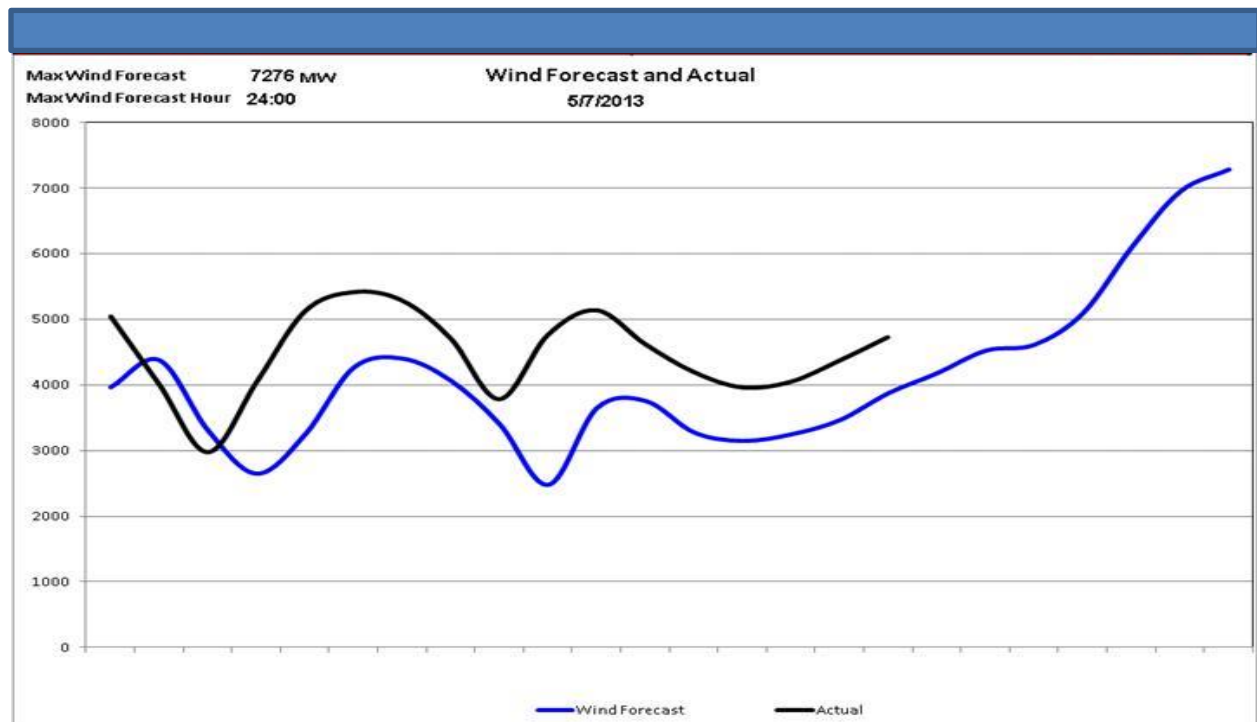


On the day referenced in Figure 3, wind generation dropped 93% (a total loss of 6,500 MW) over 13.5 hours. An over reliance on wind coupled with a possible 93% reduction of wind generation on any given day requires an increased reliance on flexible gas generating units and

less on base load units.⁴ This introduces inefficiencies into ERCOT's system and likely means that nuclear generating units will be backed down when it is windy, only to be replaced with combined cycle or simple cycle gas turbine units. Because of the variability of wind and other renewable generation occurs rapidly, in minutes, ERCOT's nuclear fleet cannot respond efficiently because the units are not designed for load following operations.

An example of what the ERCOT generation mix must be able to handle over very short periods of time is shown in Figure 4, below.

Figure 4: Variability of Wind Can Be Frequent and Extreme



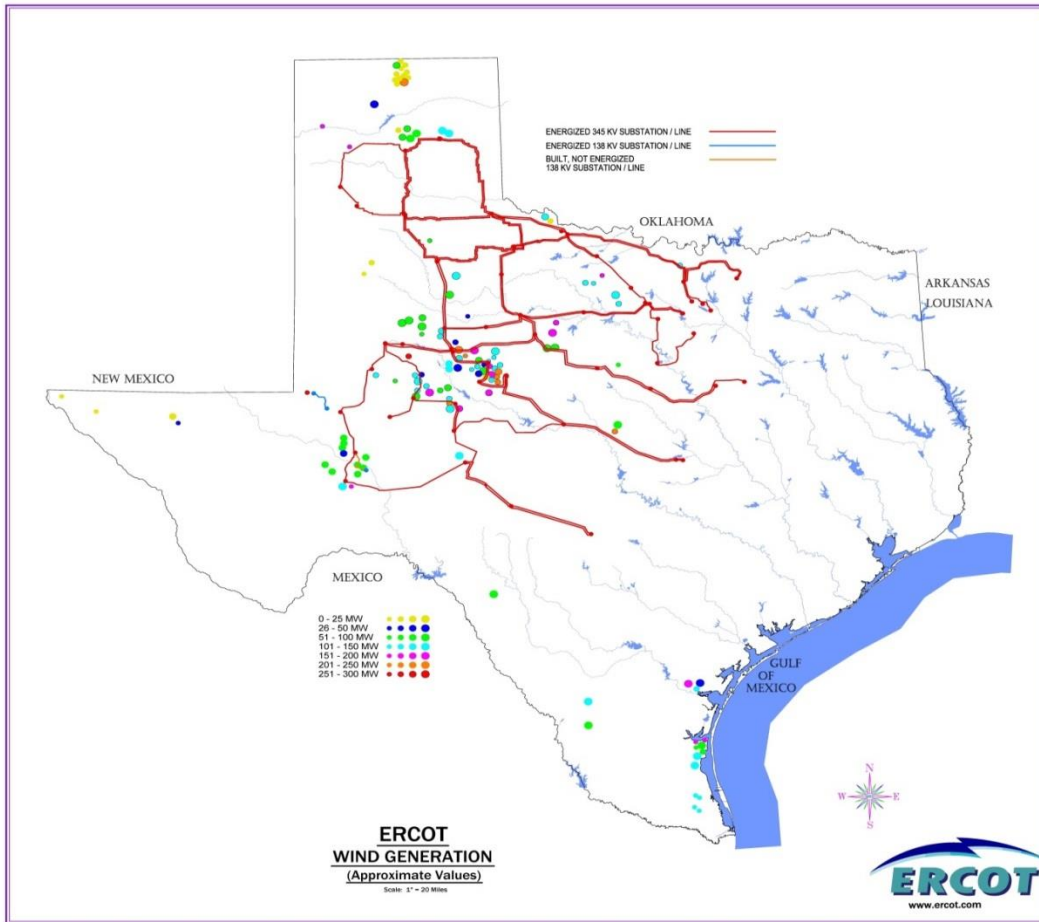
⁴Yih-huei Wan, *Analysis of Wind Power Ramping Behavior in ERCOT*, NREL Technical Report NREL/TP-5500-49218, (March 2011). “It is clear that the variability of wind power affects the system operations.” at 3. “The more installed wind power capacity will result in a higher wind power ramping-rate, and wind power can change at a very fast rate in a short-time frame.” at 13. The more wind capacity there is on the system, the greater the magnitude of the ramping events will be. Figure 4 shows a magnitude of 6,500 MW (2014). The worst case in 2008 was a 3,430 MW loss of wind power in 10.8 hours. The greater the magnitude, the less Texas can rely on base load generation like nuclear generation.

On May 5, 2013, ERCOT experienced three cycles of between 2,000 and 1,000 MW changes in wind production in a 14 hour period. This is the equivalent to having 1,500 MW of thermal generation trip off line three times in 14 hours. Flexible natural gas-fired generation can handle the variability of wind and other renewable generation best because of its ramping ability, however, even gas combined cycle generation is most efficient when operated at or near 100% of capacity.

Texas Receives No Credit for Previous Renewable Investments Made

The EPA's proposed Clean Energy Plan rule ignores the significant renewable energy development that has occurred in Texas during the preceding decade. Even with the extreme variations in wind generation that can occur over the course of the year, in 2013 Texas wind generation produced 35.917 million MWh (16.24% of the nation's non-hydro renewable generation). However, the 2012 base year selected by the EPA for the proposed Clean Power Plan rule does not give Texas credit for the societal and financial commitments to facilitate renewable energy. From 2005 through 2011 Texas added over 8,500 MW of wind capacity, of which 8,300 MW were built within ERCOT. Figure 5 shows the \$6.9 billion investment Texas has made in 3,600 miles of new competitive renewable energy zone (CREZ) transmission lines, a project which was completed in December 2013.

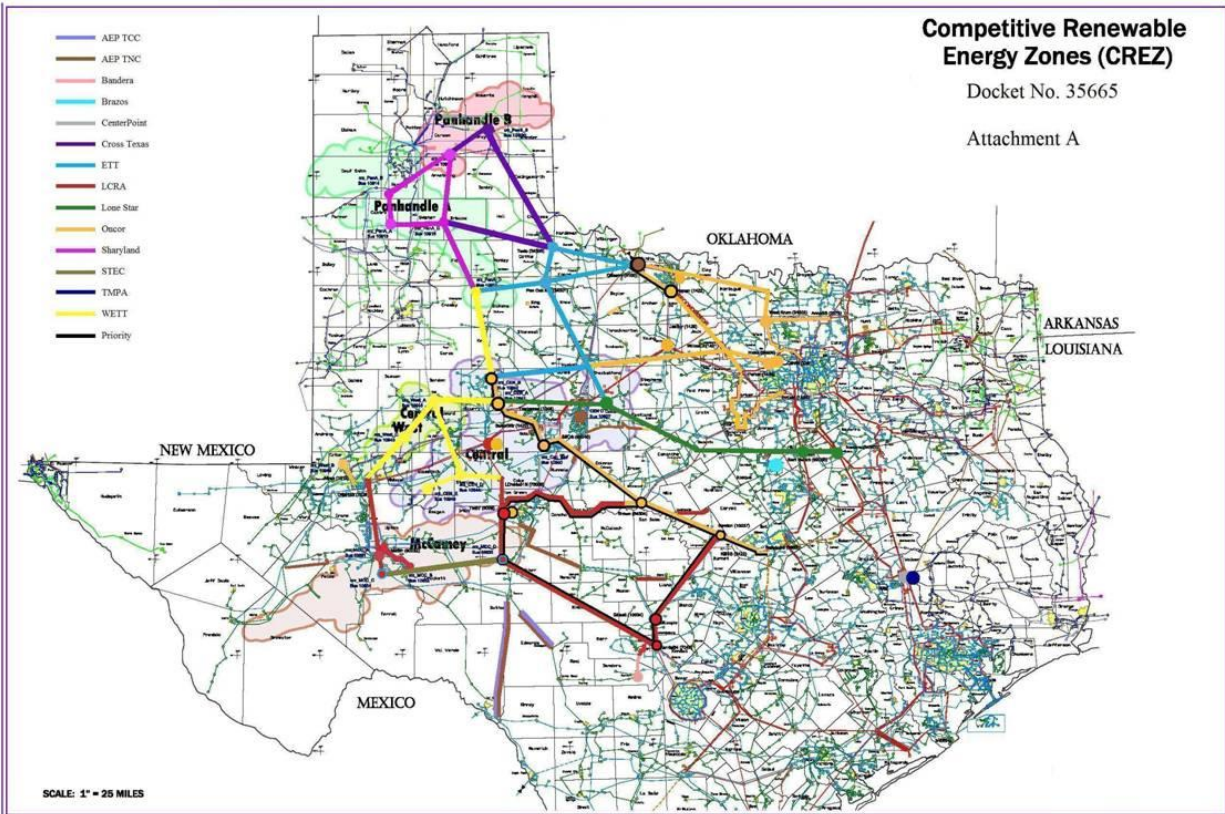
Figure 5: Competitive Renewable Energy Zone (CREZ) Transmission Lines



The investment in CREZ infrastructure has contributed to a more than threefold increase in wind generation as a percentage of ERCOT generation from 2007 to 2013 (3%-9.9%)⁵, yet Texas receives no credit for the growth between 2005 and 2012 because of the 2012 base year used by the EPA. Figure 6 demonstrates the significance of the CREZ project in relation to ERCOT's overall transmission system.

⁵ Potomac Economics, LTD., *2013 State of the Market Report for the ERCOT Wholesale Electricity Markets*, at 63 (September 2014). Potomac Economics LTD. is the independent market monitor for the ERCOT market.

Figure 6: The Entire ERCOT Transmission System



EPA Overestimates the Generating Capacity of Texas Wind from a Reliability Standpoint

In determining the BSER for Block 3, EPA uses a capacity factor for Texas wind of between 39% and 41%.⁶ For reliability purposes, ERCOT assigns wind an 8.7% wind capacity factor which is the estimated availability of wind during summer peak. ERCOT is late in the process of recalculating the effective load-carrying capability (ELCC) of wind and is expected late next month to assign West Texas wind an ELCC of 14.2% and coastal wind and ELCC of 32.9%.⁷ Both figures are still substantially below the capacity factor the EPA assigns to Texas wind energy.

Texas Has Already Achieved Substantial Progress in Reducing Emissions

From 2000 to 2011 Texas reduced its total carbon emissions by more than any other state.⁸ The State has accomplished this result while growing its economy more than any other state (33.5%).⁹ The reductions made by Texas over those 12 years amount to 13.3% of the country's reductions. Texas has reduced its total CO₂ emissions by 65 million metric tons (and also achieved significant reductions in NO_x and SO₂ emissions), all while expanding its economy by a third. Yet it appears EPA, under its proposed Clean Power Plan rule, will require far more from Texas than it asks from other states.

⁶ United States Environmental Protection Agency, *Documentation for EPA Base Case v.5.13 Using the Integrated Planning Model*, Table 4-21, at 4-46, referencing The United States Department of Energy's National Renewable Energy Laboratory (NREL) capacity factors for different wind classes. For wind class in Texas, refer to NREL's United States Wind Resource Map (50m), <http://www.nrel.gov/gis/pdfs/windmodel4pub1-1-9base200904enh.pdf> (May 6, 2009). From the map, wind power class in Texas, is shown as either wind power class 3 or 4.

⁷ ERCOT Nodal Protocol Revision Request 611, Scheduled for ERCOT Board of Directors vote October 13, 2014. ERCOT expects to be using two capacity factors for Texas wind.

⁸ U.S. Energy Information Administration, *State-Level Energy-Related Carbon Dioxide Emissions, 2000 – 2011*, (August 2014) at 6. See Table 1. State energy-related carbon dioxide emissions by year (2000-2011), which show a 64.8 million metric ton reduction. This is total carbon reduction, not limited to sectors.

⁹ Federal Reserve Bank of St. Louis, *Real Total Gross Domestic Product By State For Texas*, plotted from 1997 until 2013, <http://research.stlouisfed.org/fred2/series/TXRGSP>

The EPA's Proposed Clean Power Plan Timelines Are Problematic

The Comment Deadline

There are several timelines under the EPA's proposed Clean Power Plan that are a problem or raise questions. The first is the comment deadline. Mid-October is not sufficient time to evaluate the intricacies of the over six hundred page proposal, particularly when considering the wide scope of the proposed Clean Power Plan rule. Effectively, the EPA is proposing to restructure the nation's electric system, which has slowly evolved over a century. This is a dramatic and unprecedented undertaking which requires considerable thought and analysis. It is likely that Texas will ask for more time to file comments.

The Intermediate Goal Deadline of 2020

The second issue is the timeline for intermediate goal achievement. The intermediate 2020 target is an unrealistic timeline given the time it will take to plan a Texas SIP, much less implement it. In Texas, the legislature meets every two years, in odd numbered years. The earliest the proposed rule could possibly go into effect would be sometime next summer, and at that point the 2015 legislative session is over. Consequently the next time the Texas legislature would convene is January 2017. If the BSER "building blocks" remain in a final rule as proposed, it will require legislation, before a Texas SIP could be filed with the EPA. While the ERCOT market would likely continue to make the market driven reductions in CO₂, new generation or even fuel conversions of existing generating units have to be carefully scheduled in order to maintain grid reliability, whether in ERCOT, or the other RTO/ISOs. If new transmission upgrades are required, even in ERCOT (where transmission can be built faster than elsewhere in the country) it will still require 4-7 years of planning, siting and construction to accomplish.

Conclusion

I would like to thank the members of the Energy and Power Subcommittee of the House Committee on Energy and Commerce for the opportunity to appear before them today. Devoting time and effort discussing questions raised by the EPA's proposed Clean Power Plan is an exceptionally important undertaking. EPA's proposed rule, if adopted, is likely to have a dramatic effect on electric reliability, the economy and the environment in Texas, all other states, and the nation. The rule must be thoughtfully and carefully considered before its implementation.

ATTACHMENT F

February 26, 2014

VIA WWW.REGULATIONS.GOV

Administrator Howard Shelanski
Office of Information and Regulatory Affairs
Office of Management and Budget
New Executive Office Building
Washington, D.C. 20503

Re: Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order No. 12866; Docket ID OMB-OMB-2013-0007; Comments of The American Chemistry Council, the American Coalition for Clean Coal Electricity, the American Exploration & Production Council, the American Forest & Paper Association, the American Fuel & Petrochemical Manufacturers, the American Iron & Steel Institute, the American Petroleum Institute, America's Natural Gas Alliance, the Brick Industry Association, the Council of Industrial Boiler Owners, The Fertilizer Institute, the Independent Petroleum Association of America, the National Association of Home Builders, the National Association of Manufacturers, the National Mining Association, the National Oilseed Processors Association, the Natural Gas Supply Association, the Portland Cement Association, and the U.S. Chamber of Commerce

Dear Administrator Shelanski:

The American Chemistry Council, the American Coalition for Clean Coal Electricity, the American Exploration & Production Council, The American Forest & Paper Association, the American Fuel & Petrochemical Manufacturers, the American Iron & Steel Institute, the American Petroleum Institute, America's Natural Gas Alliance, , the Brick Industry Association , the Council of Industrial Boiler Owners, The Fertilizer Institute, the Independent Petroleum Association of America, the National Association of Home Builders, the National Association of Manufacturers, the Natural Gas Supply Association, the National Mining Association, the National Oilseed Processors Association, the Portland Cement Association, and the U.S. Chamber of Commerce (collectively, "the Associations")¹ hereby submit the following comments in response to the November 26, 2013, Office of Management and Budget ("OMB") invitation for public comments on the Technical Support Document entitled *Technical Update of*

¹ See Attachment 1 for each organization's statement of interest.

*the Social Cost of Carbon (“SCC”) for Regulatory Impact Analysis Under Executive Order 12866.*²

Member companies of the Associations will be impacted by the SCC Estimates because many of them manufacture products that, when combusted, result in greenhouse gas (“GHG”) emissions (including carbon dioxide (“CO₂”)), and because, in the course of their business, they emit CO₂. When this Administration, or any subsequent one, promulgates further regulation of these products or emissions, under Executive Order 12866, such proposals and rules to the extent permitted by law, must be based on “a reasoned determination that the benefits of the intended regulation justify its costs.” The SCC Estimates are generated through a formal interagency process, whose purpose is to affect and bind agency regulatory actions and regulations. As such, the SCC Estimates, though subject to periodic re-examination, mark the consummation of the government’s cost-benefit analysis, which, in turn, is binding on federal agencies pursuant to Executive Order 12866. Indeed, the pattern and practice of the government has confirmed that federal agencies view the SCC Estimates as binding and already have relied upon them in crafting and adopting regulations that affect the Associations’ members.³ Our members, therefore, have a direct and concrete interest in ensuring that any SCC Estimates are based on transparent processes, accurate information, and rational assumptions, and are within the reach of the current scientific understanding and impact models. To be clear, the Associations are not herein discussing the existence or potential causes of climate change. Instead, we are questioning the IWG’s estimates of the social cost of carbon, based on estimates of complex economic impacts hundreds of years in the future, which in turn are based on present day understanding of current and future carbon emissions.

These comments address issues related to the SCC Estimates published in February 2010⁴ and May 2013,⁵ including the most recent technical update issued in November 2013.⁶ On

² 78 Fed. Reg. 70,586 (Nov. 26, 2013).

³ E.g., The U.S. Environmental Protection Agency (“EPA”) frequently has used the 2010 SCC Estimates in cost-benefit analyses supporting Clean Air Act rules. See, e.g., 77 Fed. Reg. 62,624 (Oct. 12, 2012) (light-duty vehicle CAFE standards); 77 Fed. Reg. 49,489 (Aug. 16, 2012) (NESHAPs for the oil & gas source category); 77 Fed. Reg. 9,304 (Feb. 16, 2012) (NESHAPs for the power plant source category); 75 Fed. Reg. 25,324 (May 7, 2010) (tailpipe GHG/CAFE rules). The Department of Energy (“DOE”) has used the May 2013 SCC Estimates in connection with a rulemaking addressing the energy efficiency standard for microwave ovens. 78 Fed. Reg. 36,316 (June 17, 2013). Likewise, DOE used the May 2013 SCC Estimates to support a recently finalized energy efficiency rule for metal halide lamp fixtures (79 Fed. Reg. 7,746 (Feb. 10, 2014)) and proposal rules for commercial refrigeration equipment (78 Fed. Reg. 55,889 (Sept. 11, 2013)); walk-in coolers and freezers (78 Fed. Reg. 55,888 (Sept. 11, 2013)); residential furnace fans (78 Fed. Reg. 64067 (Oct. 25, 2013)); commercial and industrial electrical motors (78 Fed. Reg. 73,590 (Dec. 6, 2013)); Industrial Air Compressors (79 Fed. Reg. 6,839 (Feb. 5, 2014)); and, external power supplies (79 Fed. Reg. 7,846 (Feb 10, 2014)).

⁴ Interagency Working Group on Social Cost of Carbon, United States Government, *Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866* (February 2010) (“2010 Estimate”).

⁵ Interagency Working Group on Social Cost of Carbon, United States Government, *Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866* (May 2013; revised Nov. 2013) (“2013 Estimate”).

September 4, 2013, a group of trade associations, including many of the undersigned parties, submitted a Petition for Correction of the 2010 and 2013 Estimates pursuant to the Information Quality Act⁷ (“IQA”) requesting that the Technical Support Documents (“TSD”) and SCC Estimates be withdrawn and not used in rulemaking and policymaking for a variety of reasons further explained herein.⁸ Importantly, while OMB responded to that IQA Petition the evening of January 24, 2014, OMB’s response merely defended the TSD through text borrowed from the TSD, provided no additional details about the interagency processes that developed the TSD or the SCC Estimates, declined to withdraw the TSD or SCC Estimates, or prohibit their use in rulemaking.⁹ Accordingly, the Associations request OMB reconsider its response to this IQA petition and continue to urge OMB to withdraw and instruct federal agencies to cease the rulemaking and policymaking uses of the SCC Estimates and TSDs for the following reasons:

1. The SCC Estimates fail in terms of process and transparency. The SCC Estimates fail to comply with Office of Management and Budget (“OMB”) guidance for developing influential policy-relevant information under the IQA. The SCC Estimates are the product of a “black box” process and any claims to their supposed accuracy (and therefore, usefulness in policymaking) are unsupported.
2. The models with inputs (hereafter referred to as “the modeling systems”) used for the SCC Estimates and the subsequent analyses were not subject to peer review.
3. Even if the process used to develop the SCC Estimates was transparent, rigorous, and peer-reviewed, the modeling conducted in this effort does not offer a reasonably acceptable range of accuracy for use in policymaking.
4. The Interagency Working Group (“IWG”) has failed to disclose and quantify key uncertainties to inform decision makers and the public about the effects and uncertainties of alternative regulatory actions as required by OMB.
5. By presenting only global SCC estimates and downplaying domestic SCC estimates in 2010 and 2013, the IWG has severely limited the utility of the SCC for use in cost-analysis and policymaking.
6. The IWG must (i) supplement the record to provide all of the data, models, assumptions and analyses relied on to arrive at the SCC Estimates, and (ii) allow the public a reasonable opportunity to review and comment on the supplemented record.

⁶ See Howard Shelanski, Administrator of the Office of Information and Regulatory Affairs at the Office of Management and Budget, *Refining Estimates of the Social Cost of Carbon* (Nov. 1, 2013) (available at www.whitehouse.gov/blog/2013/11/01/refining-estimates-social-cost-carbon) (“November 2013 Revision”).

⁷ P.L. 106-554, §515, 144 Stat. 2763 (2001).

⁸ The November 2013 Revision contained no substantive analytical changes. As such, the comments detailed regarding the February 2010 and May 2013 Estimate herein and in the Associations’ IQA Petition apply with equal force to the most recent SCC Estimate issued in November 2013.

⁹ January 24, 2014 Letter from Howard A. Shelanski (Director, Office of Information and Regulatory Affairs to Wayne D’Angelo (Kelley Drye & Warren, LLP) (“OMB IQA Response”).

Importantly, that OMB is now providing a mechanism for public comment does not make OMB's SCC estimation effort transparent or the process collaborative.¹⁰ Despite repeated requests from Congress, the Associations, and many other individuals and organizations, OMB has not made available to the public all of the information necessary to allow the public and regulated community to evaluate the SCC Estimates. By not providing any information on the policy decisions, inputs, and assumptions that underpin the SCC Estimates, OMB's "request for comments" is meaningless. By withholding this information from the public, OMB deprives the IWG and this Administration of the benefit of outside input on the validity of the critical decisions, inputs, and assumptions that form the basis of the SCC Estimates. Providing an opportunity to comment, but then denying or withholding access to the data necessary to inform such comments, may be designed to give a superficial appearance of transparency and collaboration, but, in reality, merely perpetuates an impermissibly opaque process.¹¹ Instead of including the critical inputs and assumptions that serve as the basis for the SCC Estimates in the rulemaking docket or other public forum, some of the undersigned Associations have been compelled to seek these necessary documents through the Freedom of Information Act ("FOIA"). While some of the participating agencies have provided partial, and heavily redacted responses to the FOIA requests, many of the participating agencies unlawfully have refused to respond to these requests at all.¹² The record should remain open until these agencies have complied with the law and produced these documents.

That the Environmental Protection Agency ("EPA") and Department of Energy ("DOE") are proceeding to utilize the SCC Estimates¹³ without even waiting for the comment period to close on the docket for such estimates confirms the tangible harm to the Associations' members

¹⁰ For example, several regulatory actions and proposals have been issued prior to OMB seeking public comment on the SCC Estimates, yet none have been retracted pending receipt and review of the comments sought here. *See, e.g.*, 78 Fed. Reg. 79,419 (Dec. 30, 2013) (U.S. DOE, *Energy Conservation Program for Consumer Products and Commercial and Industrial Equipment: Effect of Revised Estimates of the Social Cost of Carbon*). Critically, DOE even finalized one rule that relied on the SCC without awaiting the consummation of this rulemaking (metal halide lamps (78 Fed. Reg. 7,746)). EPA has identified 19 rulemakings since 2009 that utilized federal SCC Estimates. *See* Letter dated January 16, 2014, from Joel Beauvais, EPA Associate Administrator, Office of Policy, to Senator David Vitter (Table 1).

¹¹ To be able to meaningfully comment on the SCC Estimates, the public record must be supplemented with, at a minimum: (i) the specific versions of the IAMs upon which the government relied to generate the SCC Estimates (including the source codes for the models); (ii) the inputs and assumptions used in the model runs upon which the government relied to generate the SCC Estimates (including, but not limited to, assumptions on discounting, equilibrium climate sensitivity, and socio-economic variables); (iii) the results of any modeling runs or scenarios generated by the IAMs upon which the government relied; (iv) technical analyses regarding the government's decision on how it averaged the results of the IAM model runs; and (v) any analyses conducted by and conclusions reached by the government regarding the uncertainties associated with each of the IAMs and calculating the SCC Estimates. Without this information in the record, the public does not have a meaningful opportunity to understand, evaluate and comment upon the SCC Estimates

¹² 5 U.S.C. §552(a)(6).

¹³ 78 Fed. Reg. 79,419 (Dec. 30, 2013); *See* Regulatory Impact Analysis for the Proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units (EPA-452/R-13-003 (Sept. 2013)).

and unambiguously confirms that OMB does not intend to use the public comment process as a means of updating and improving its SCC Estimates or to obtain the best available information.

Although the Associations are concerned that OMB is simply replacing the IWG's "black box" analysis with its own opaque process, the importance of this issue compels us to provide input to the best of our abilities using the limited (and inadequate) information made available to the Associations. As such, the Associations reiterate that, given the significant issues described herein, the SCC Estimates and Technical Support Documents should be withdrawn, pending correction through a transparent, public process.¹⁴ Further, we request OMB not to utilize, and to direct publicly other executive branch agencies not to utilize, the SCC Estimates for any regulatory action or policymaking.

I. BACKGROUND

In June 2013, the IWG released the revised TSD on SCC recommended for use in Regulatory Impact Analysis ("RIA"). In the revised TSD, the IWG continued to express the SCC as the dollars/ton of monetized damages associated with an incremental increase in carbon emissions in a given year. The IWG used the same basic methodology that it used in 2010 to estimate the SCC figures. As per the 2010 TSD, the SCC values were estimated using the average results from the same three integrated assessment models at the same discount rates – 2.5%, 3%, and 5% – and a fourth value using the 95th percentile estimate at the 3% discount rate. The IWG used the same five climate change scenarios utilized in 2010. The IWG indicated the only changes that altered the SCC values were the new versions and runs of the three assessment models.

For example, the new SCC values estimated for 2020 in 2007 dollars were \$12, \$43, \$65, and \$129 for the 5%, 3%, 2.5%, and 95th percentile of the 3% discount rates, respectively. By comparison, the SCC values in the 2010 TSD for 2020 were \$7, \$26, \$42, and \$81, respectively (all in 2007 dollars). At the key discount rate of 3% (considered the central value), the new SCC

¹⁴ Such a process is mandated by Executive Order 13563, January 18, 2011, which states:

Sec. 2. Public Participation. (a) Regulations shall be adopted through a process that involves public participation. To that end, regulations shall be based, to the extent feasible and consistent with law, on the open exchange of information and perspectives among State, local, and tribal officials, experts in relevant disciplines, affected stakeholders in the private sector, and the public as a whole.

(b) To promote that open exchange, each agency, consistent with Executive Order 12866 and other applicable legal requirements, shall endeavor to provide the public with an opportunity to participate in the regulatory process. To the extent feasible and permitted by law, each agency shall afford the public a meaningful opportunity to comment through the Internet on any proposed regulation, with a comment period that should generally be at least 60 days. To the extent feasible and permitted by law, each agency shall also provide, for both proposed and final rules, timely online access to the rulemaking docket on regulations.gov, including relevant scientific and technical findings, in an open format that can be easily searched and downloaded. For proposed rules, such access shall include, to the extent feasible and permitted by law, an opportunity for public comment on all pertinent parts of the rulemaking docket, including relevant scientific and technical findings.

Estimate of \$43 is approximately 65% higher than the 2010 value. By comparison, in 2009, the IWG estimated a central value of \$19 and, in 2008, the U.S. Department of Transportation (“DOT”) estimated a central value of \$7.¹⁵ Thus, in a span of five years, the central SCC Estimate to be used in regulation has changed multiple times and increased 600 percent.

The size and frequency of these increases to IWG’s SCC Estimates call into question the accuracy and reliability of the IWG’s most recent estimate (the third proffered in 2013 alone), and further indicate that the process and models through which the estimates were generated were either flawed or unsuitable for generating estimates that reasonably could inform important regulatory and policy decisions. As discussed further below, the first step in addressing these potential flaws and suitability issues is for OMB and IWG to shed light on these processes, allow for an informed and transparent discussion, and present IWG’s estimates as accurately as possible.

II. INFORMATION QUALITY ACT GUIDELINES

The process for generating the SCC Estimates violates the IQA. The IQA requires federal agencies to take steps to maximize the quality, objectivity, and integrity of the information they disseminate, and to provide a mode of redress to correct flawed or incomplete information. Consistent with its directive to other agencies and entities, OMB developed its own guidelines (“IQA Guidelines”) that require that the information it disseminates meets standards for objectivity, utility, and integrity.¹⁶ The “objectivity standard” focuses on whether the information is “accurate, reliable, and unbiased and whether the information is presented in an accurate, clear, complete, and unbiased manner.”¹⁷ The “integrity standard” refers to information security, such as protection of information from unauthorized access or revision, while the “utility standard” refers to the usefulness of the information for the intended audience’s anticipated purposes.¹⁸

OMB’s Guidelines require it to maximize the quality of disseminated information that it classifies as influential. “Influential information” generally refers to information that “will have a clear and substantial impact on important public policies or important private sector decisions.”¹⁹ Without question, the SCC Estimates, upon which a number of agencies already have based regulations and which numerous agencies may base billions, if not trillions, of dollars of regulation, are “influential information” that has had and will have a clear and substantial impact on important public policies and important private sector decisions.²⁰

¹⁵ 2010 TSD at 4.

¹⁶ Office of Management and Budget, *Information Quality Guidelines* (Oct. 1, 2002).

¹⁷ *Id.* at 8.

¹⁸ *Id.* at 1.

¹⁹ *Id.* at 8.

²⁰ *Id.*

Further, under OMB Guidelines, such influential information must meet a higher level of “transparency.”²¹ According to OMB, transparency requires that its findings be reproducible, within an acceptable range of imprecision, by third parties.²² Influential information must also be transparent with respect to: (1) the source of the utilized data; (2) the various assumptions employed; (3) the analytic methods applied; and (4) the statistical assumptions employed.²³ All these transparency elements are important considerations in any objective, third-party review and analysis of Agency information.

OMB imposes these guidelines on itself as well as on the information on which it relies. It requires OMB staff, and the working groups it oversees, to acquire relevant information by acceptable and unbiased methods.²⁴ Further, information collected must generally display indicia of reliability such as being subjected to peer review or being founded on transparent and reproducible methods.

OMB’s obligations under the IQA are significant, requiring OMB to issue government-wide guidelines that “provide policy and procedural guidance to Federal agencies for ensuring and maximizing the quality, objectivity, utility, and integrity of information (including statistical information) disseminated by Federal agencies.” These obligations were put in place by Congress and are supported by an Administration-wide effort to make informed and transparent decisions based on sound science.²⁵ The IQA guidelines, peer review guidelines, and internal protocols that OMB uses are intended to ensure the Administration’s disseminations are objective, unbiased, and robust. Importantly, OMB, as the entity that developed and oversees the IQA’s guidelines to federal agencies, has a profound and unique interest in ensuring those guidelines are followed to the greatest extent possible in its own regulatory decision making. As detailed below, the development of the SCC Estimates failed to follow these OMB guidelines.

III. THE SCC ESTIMATES ARE THE PRODUCT OF A FUNDAMENTALLY FLAWED AND IMPERMISSIBLY OPAQUE PROCESS

The SCC Estimates represent specific monetary values per metric ton of CO₂ intended to be used in regulatory impact analyses required under Executive Order 12866 to estimate the costs and benefits of major federal regulations.²⁶ These values, developed by the IWG, reflect an incredibly broad range that corresponds to different assumed discount rates that purport to translate estimated future dollar damages from current emissions into a present value. These estimates are derived from values obtained from computer models, known as the Integrated

²¹ *Id.* at 2.

²² *Id.*

²³ 67 Fed. Reg. 369, 374 (Jan. 3, 2002).

²⁴ *Id.* at 23.

²⁵ See President Obama’s Memorandum for the Heads of Executive Departments and Agencies: Transparency and Open Government (74 Fed. Reg. 4685 (Jan. 21, 2009)) (“My Administration is committed to creating an unprecedented level of openness in Government.”); see also President Obama’s Memorandum for the Heads of Executive Departments and Agencies: Scientific Integrity. (“Science and scientific processes must inform and guide decisions of my Administration on a wide range of issues.”).

²⁶ Neither the TSDs nor the SCC Estimates attempt to monetize costs of methane emissions. See 2010 TSD.

Assessment Models (“IAMs”), that, in short, purport to represent the linkage from (1) greenhouse gas emissions, to (2) global temperature changes, to (3) the “climate change impacts” projected to result from these temperature changes, to (4) the monetized economic damages of these effects. The 2010 and 2013 SCC Estimates were derived by inputting a set of undisclosed assumptions developed by the IWG into three particular IAMs selected by the IWG from a wider class of IAMs: DICE (Dynamic Integrated model of Climate and Economy), FUND (Framework Uncertainty, Negotiation and Distribution), and PAGE (Policy Analysis for the Greenhouse Effect).²⁷

The process of selecting the models and input assumptions, including much of the basic information underlying these decisions, has been insulated from public scrutiny. The resulting SCC Estimates are a product of this fundamentally flawed process that failed to comply with basic IQA requirements designed to enhance and ensure the credibility of data used to make critical regulatory decisions.²⁸ These flaws are discussed in detail below.

A. The IWG Estimation Process Was Not Transparent

In his March 9, 2009, “Memorandum for the Heads of Executive Departments and Agencies” on “Scientific Integrity” (“Scientific Integrity Memo”), President Obama called on his Administration to commit to procedures and a code of conduct that ensures scientific integrity and builds public trust. President Obama’s opening line of that memorandum could not be more relevant and directly applicable to the SCC Estimates and the processes which underlie them:

Science and the scientific process must inform and guide decisions of my Administration on a wide range of issues, including improvement of public health, protection of the environment, increased efficiency in the use of energy and other resources, mitigation, and protection of national security. The public must be able to trust the science and the scientific process informing public policy decisions.

In furtherance of these important goals, President Obama instructed “[t]o the extent permitted by law, there should be transparency in the preparation, identification, and use of scientific and technological information in policymaking.” The requirement of transparency is at the core of

²⁷ DICE (W. Nordhaus, Yale University), PAGE (C. Hope, University of Cambridge UK), and FUND (R. Tol, Ireland Economic and Social Institute and Carnegie Mellon University).

²⁸ In addition to the procedural flaws discussed in detail below, the SCC Estimate itself is contrary in significant ways to OMB’s own guidance on conducting cost-benefit calculations intended to guide regulatory agency decision makers. See OMB Circular A-4, “Regulatory Analysis” (Sept. 2003) (as amended) (“OMB Circular A-4”). For example, cost-benefit normally applies to specific decisions relating to individual rulemakings. OMB Circular A-4 states that a good regulatory analysis cannot be formulaic. *Id.* at 2, ¶5. Yet the SCC Estimate provides a formulaic result – developed in isolation – that is intended to be applied to any regulatory action addressing carbon emissions. It is necessary only to plug in the proper cost number and calculate benefits for any planned regulatory actions. The SCC Estimate similarly ignores Circular A-4’s requirement that costs and benefits must be evaluated and compared to each other. The SCC Estimate is based entirely on the projected benefit of avoiding each ton of carbon that is modeled to cause damage at some point in the future. Further concerns with OMB’s compliance with Circular A-4 are discussed in subsequent sections of these Comments.

the OMB's IQA reproducibility standards mandated for "influential information" such as the SCC Estimates.

Under OMB's IQA Guidelines, "influential information" must meet a higher level of "transparency."²⁹ According to OMB, transparency requires that the OMB/IWG findings be reproducible, within an acceptable range of imprecision, by third parties.³⁰ Influential information must be transparent with respect to: (1) the source of the utilized data; (2) the various assumptions employed; (3) the analytic methods applied; and (4) the statistical assumptions employed. All of these elements of transparency are important considerations in any objective, third-party critical review and analysis of the SCC Estimate.³¹

According to OMB in the IQA Rule:

[T]he primary benefit of public transparency is not necessarily that errors in analytic results will be detected, although error correction is clearly valuable. The more important benefit of transparency is that the public will be able to assess how much an agency's analytic results hinge on the specific analytic choices made by the agency. Concreteness about analytic choices allows, for example, the implications of alternative technical choices to be readily assessed. This type of sensitivity analysis is widely regarded as an essential feature of high-quality analysis, yet sensitivity analysis cannot be undertaken by outside parties unless a high degree of transparency is achieved.³²

OMB, as the disseminator of the SCC Estimates, and the overseer of the IWG, has a duty to ensure the transparency of the IWG estimation process. That duty has not been met. The public knows nothing about the IWG other than the identity of the agencies and entities that make up the group and the fact that this group of unspecified officials provided three substantially different SCC estimates in the period between 2010 and 2013.

OMB has not revealed the identity of the IWG participants or any information from which to make an assessment as to their expertise or qualification to participate in a group tasked to estimate the SCC. According to OMB Circular A-4's directive to agencies (presumably applicable also to OMB): "You should also disclose the use of outside consultants, their qualifications, and history of contracts and employment"³³ The public does not even know whether all the IWG's listed agencies and entities provided personnel or what levels of engagement each of the agencies actually had in the development of the SCC Estimates. The public does not know whether or how government contractors were used in the development process. Further, OMB has not revealed how these unidentified individuals collaborated. The public does not know whether, or how often, they met, what was discussed, what information

²⁹ OMB IQA Guidelines at 2.

³⁰ 67 Fed. Reg. at 378.

³¹ 67 Fed. Reg. at 374.

³² 67 Fed. Reg. at 374.

³³ OMB Circular A-4 at 17.

was considered, what information was rejected, or how decisions were made. This information must be made available so that the public can conduct a critical review.

For sake of perspective, consider EPA's recent efforts to evaluate whether the Agency can quantify with sufficient accuracy the "economy-wide" impacts of its air regulations.³⁴ Unlike OMB's SCC Estimates, which attempt to monetize global impacts of U.S. emissions of a ubiquitous substance centuries into the future, EPA's efforts are far more modest because the Agency is only attempting to consider: (1) domestic costs; (2) of traditional pollutants with more direct "dose-response" functions; (3) emitted by far fewer industrial sources; (4) within discrete timeframes.

Even still, EPA claims its effort presents "serious technical challenges . . ."³⁵ To address these challenges, EPA presented the issue to the independent Science Advisory Board ("SAB") and provided public notice in the Federal Register. EPA published detailed draft charge questions it would present to the SAB and a similarly detailed analytical blueprint and list of materials for the SAB to consider. Importantly, EPA provided public notice of the provision of all these materials and is seeking comment on them.

In undertaking the far more complex and ambitious task of estimating the SCC, OMB undertook a conspicuously different approach. OMB tasked its effort to the IWG without any public notification. OMB never published nor took comment on its charge questions to the IWG, or the analytical blueprint or materials it requested the IWG consider. The public only learned of the IWG, its important role within the Federal government, and its SCC estimates when they were referenced in an efficiency standard for microwave ovens.

The SAB also operates in a starkly different manner than the IWG. The SAB provides notice of its meetings, as well as opportunities to observe and participate. The SAB's advisories and consultations with EPA are published, as are EPA's responses to such. The SAB discloses its members, provides detailed biographies of each members' affiliation and expertise, publishes criteria for participation in the SAB, and offers the public an opportunity to nominate members.

The IWG, on the other hand, provides no notice of its meetings (before or after they occur), and the public has no opportunity to observe, participate in, review minutes, communications, or even summaries of such. The IWG's interaction and consultation with OMB is unknown, and no records of charges or instructions are made available. The IWG's members are secret, as are the means by which they are selected. Their expertise are entirely unknown. All that is known about IWG members are the identities of the federal entities on whose behalf they participate. It is not even known whether they are Federal employees, contractors, or third parties.

While EPA and SAB processes are by no means perfect, and the Associations may well disagree with their outcomes, the contrast between the transparency and engagement in EPA's

³⁴ 79 Fed. Reg. 6899 (Feb. 5, 2014).

³⁵ *Id.* at 6900.

“economy-wide modeling effort,” and the opacity of OMB’s “global” modeling effort is both striking and disturbing. OMB has failed to comply with the transparency policies that it promulgated for developing influential policy-relevant information under the IQA and imposes on other agencies and executive offices. The SCC Estimates are the product of an opaque process, riddled with uncertainties. Any claims to their supposed accuracy (and, therefore, usefulness in policymaking) are unsupported. None of these failures in transparency has been remedied by allowing for after-the-fact comment on the SCC Estimates. As noted above, without access to the fundamental information underlying the SCC Estimates necessary to formulate comments and some indication that OMB actually will consider comments, OMB’s solicitation provides only the impression of transparency.

B. The Modeling Systems (Models With Inputs) And Subsequent Analyses Were Not Subject To Peer Review

OMB and the IWG masked the inherent flaws and limitations of the SCC Estimates by not exposing the modeling systems, inputs, and results (the SCC Estimates) to peer review. As OMB’s Final Information Quality Bulletin for Peer Review (“Peer Review Bulletin”) states, “[p]eer review is one of the most important procedures to ensure that the quality of published information meets the standards of the scientific and technical community.”³⁶ Further, President Obama’s 2009 Scientific Integrity Memorandum states that “[w]hen scientific or technical information is considered in policy decisions, the information should be subject to well established scientific processes, including peer review”

OMB’s IQA Guidelines recognize the critical importance of peer review in government decision-making, and point to the existence of peer review as providing a presumption of objectivity.³⁷ Similarly, EPA, which already has relied upon the SCC Estimates, recognizes that the hallmark of scientific integrity is a robust and independent peer review process.³⁸ According to EPA guidance,

[p]eer review is conducted by qualified individuals (or organizations) who are independent of those who performed the work, and who are collectively equivalent in technical expertise (*i.e.*, peers) to those who performed the original work. Peer review is conducted to ensure that activities are technically supportable, competently performed, properly documented, and consistent with established quality criteria.³⁹

Further, EPA has recognized in its peer-review guidance that, particularly when reviewing influential findings such as the SCC Estimates, a peer reviewer must be independent to be

³⁶ Memorandum for Heads of Departments and Agencies from Josh B. Bolton, Director, OMB “Issuance of OMB’s ‘Final Information Quality Bulletin for Peer Review’” at 2 (Dec. 16, 2004).

³⁷ 67 Fed. Reg. at 377.

³⁸ *Peer Review Handbook, 3rd Edition, Prepared for the U.S. Environmental Protection Agency by Members of the Peer Review Advisory Group for EPA’s Science Policy Council, EPA/100/B-06/002.*

³⁹ *Id.* at 12.

credible, defensible, and unbiased.⁴⁰ Indeed, peer review and adherence to sound scientific methods are required by EPA's guidelines implementing the IQA.⁴¹

Despite the fact that OMB's IQA Rule and Guidelines, as well as its Peer Review Bulletin, recognize the critical need for peer review in administrative decision-making, neither OMB nor the IWG subjected the final SCC Estimates, or their key foundations, to peer review. This failure is a critical flaw and undermines the credibility of the SCC Estimates.

That the IWG utilized models that generally may be available to the public does not sufficiently demystify the IWG selection process. There is no evidence, for example, of how the IWG addressed, if at all, the limitations of each of the selected models. The class of models known as IAMs are continuously changing and evolving. While such models attempt to predict the near and far future, they all rely on numerous assumptions – including many that are decades old, and others that simply cannot be calibrated or verified. Yet, one of the models used claims to have the capacity to predict climate impacts through the year 2595. Further, it is not clear if or how modest changes to the inputs to the FUND, DICE, and PAGE models could drastically change the SCC Estimates (*i.e.*, the sensitivity of inputs to model outcomes is not transparent). Without access to information regarding the hundreds of model inputs (or the people or processes that selected them, or developed them, or both), and their sensitivities, expertise, or biases, it is impossible to call the SCC Estimates rational or supportable. Indeed, in an analysis focused on the “damage function” component of the SCC Estimates (a source of substantial uncertainties in the models, as discussed further below), the authors admit that “the range of possible parameters leads to enormous differences in estimated [SCC] values.”⁴² The process of selecting these input parameters must be subject to transparency and peer review.

On July 18, 2013, Administrator Howard Shelanski of OMB's Office of Information and Regulatory Affairs (“OIRA”) suggested in testimony before the House Committee on Oversight and Government Reform Subcommittee on Energy Policy, Healthcare, and Entitlements that peer review of the IWG decisions was unnecessary because the FUND, DICE, and PAGE models all were subjected to their own peer review.⁴³ This suggestion is incorrect, or at least misleading, for several reasons. The SCC Estimates are not just the product of the models (flawed or limited as they may be). Rather, the SCC Estimates are the product of the data, and the policy choices that were inherent in the model input data selection. Other than for a few of

⁴⁰ *Id.* at 13.

⁴¹ *Guidelines for Ensuring and Maximizing the Quality, Objectivity, Utility, and Integrity of Information Disseminated by the Environmental Protection Agency*, EPA/260R-02-008 (Oct. 2002).

⁴² NERA Economic Consulting, “A Review of the Damage Functions Used in Estimating the Social Cost of Carbon” at 17 (Jan. 2014) (“*Damage Function Report*”) (attached).

⁴³ OMB now provides a bit more nuance that the models may not have actually been reviewed by peers, but rather than they were made available for peer review because they “were published in peer reviewed journals.” (OMB IQA Response at 3-4). However, when publishing the IQA Guidelines, OMB found that the effectiveness of “journal peer review” was “overstated,” cited to instances where flawed science was published in respected journals, and ultimately concluded that “[f]or information likely to have an important public policy or private sector impact, OMB believes that additional quality checks beyond peer review are appropriate.” (67 Fed. Reg. at 8455)

the hundreds of variables that comprise the input data set for the three models used, most members of the public, other than those allowed access by the participating executive branch agencies, have no idea of what the inputs underlying the SCC Estimates were or how they were determined. This critical “black box” encompasses not only the deterministic inputs (*i.e.*, assumed values for those inputs held constant), but also, importantly, the stochastic inputs (*i.e.*, those inputs that were selected to be variable) that supported the Monte Carlo analysis.⁴⁴ Model inputs, and the judgments, principles, and processes that generated those inputs, are critical to the model output. As the developer of the FUND model prominently and candidly acknowledges on the model’s website:

It is the developer’s firm belief that most researchers should be locked away in an ivory tower. Models are often quite useless in unexperienced hands, and sometimes misleading. No one is smart enough to master in a short period what took someone else years to develop. Not-understood models are irrelevant, half-understood models treacherous, and mis-understood models dangerous.⁴⁵

The SCC Estimates are as much a product of the inputs to the models as they are the product of the models themselves. Stated plainly, if unreliable or questionable data are entered into the models, there is no basis for concluding that reliable estimates would result. The inputs that drive the SCC Estimates (and the input selection criteria) were never peer reviewed – nor are the majority of them even known. Further, the final estimates (*i.e.*, the products of these opaque models and inputs) were never peer reviewed. That is critical, as the output of the models was manipulated further by the IWG through averaging that may be inappropriate and misleading (*see infra* §V.A). That versions of the models were made available for peer review during the model development process, or utilized in papers that were themselves peer reviewed, is necessary and important, but not sufficient. OMB and the IWG must subject the current SCC Estimates, and the decisions that generated those values, to peer review. Nor does accepting comments on the IWG’s conclusions, without providing commenters with the underlying information necessary for credible evaluation, provide a substitute for peer review. OMB’s suggestion to the contrary in the OMB IQA Response⁴⁶ is without merit. Indeed, these actions reinforce the need to conduct peer review on all subsequent model changes and inputs, which alter the estimates coming out of the models. After all, ***the May 2013 SCC Estimate is 60 percent higher than the one developed just three years ago and required further amendment within six months.*** Unfortunately, OMB and the IWG have sheltered and insulated the model choice criteria, data inputs, and analyses from outside scrutiny and peer review – and continue to do so in the present “request for comments.”

⁴⁴ Consider, for instance, the selection of discount rates for one of the few model inputs that was disclosed. If a discount rate of 7% were utilized, (as mandated by OMB Circular A-4 (at 12)), the SCC Estimates would be closer to zero and potentially even demonstrate benefits. We raise this issue, not to advocate for a particular discount rate, but to highlight that even a single model input of the hundreds can materially affect the outcomes of the models.

⁴⁵ Available at www.fund-model.org (accessed Jan. 9, 2014).

⁴⁶ OMB IQA Response at 4.

The SCC Estimates/TSD are precisely the type of influential scientific information that OMB envisioned in its Final Information Quality Bulletin for Peer Review when it stated “[m]ore rigorous peer review is necessary for information that is based on novel methods or presents complex challenges for interpretation. Furthermore, the need for rigorous peer review is greater when the information contains precedent-setting methods or models, presents conclusions that are likely to change prevailing practices, or is likely to affect policy.”⁴⁷ Importantly, the Final Information Quality Bulletin for Peer Review and the IQA under which they were promulgated characterize these as the “*minimum standards* for when peer review is required for scientific information . . .”⁴⁸

C. Selection Of The Discount Rates Used To Estimate The SCC Violated OMB Requirements And Should Be An Open Process

The choice of the discount rate arguably is the most significant factor in derivation of the SCC Estimates. Depending on the discount rate selected (as noted above and *infra* §IV.A), there is substantial variation in the amount of damages calculated and, hence, the SCC Estimate that ultimately is derived. In short, the higher the discount rate used, the lower the future predicted damage impacts. The IPCC 4th Assessment report confirms the critical nature of the discount rate used to estimate the SCC:

Notwithstanding the differences in damage sensitivity to temperature..., the effect of the discount rate on estimates of SCC is most striking. The 90th percentile SCC, for instance, is US\$62/tC for a 3% pure rate of time preference, \$165/tC for 1% and \$1,610/tC for 0%. Stern (2007) calculated, on the basis of damage calculations, a mean estimate of the SCC in 2006 of US\$85 per tonne of CO₂ (US\$310 per tonne of carbon)... Other estimates of the SCC run from less than US\$1 per tonne to over US\$1,500 per tonne of carbon. Downing et al. (2005) argued that this range reflects uncertainties in climate and impacts, coverage of sectors and extremes, and choices of decision variables.

The IWG recognized in the 2010 TSD that “the interagency group has been keenly aware of the deeply normative dimensions of both the debate over discounting in the intergenerational context and the consequences of selecting one discount rate over another.”⁴⁹ Despite the criticality of the discount rate to the SCC estimation process, OMB has failed to subject the IWG’s selection of the discount rate to peer review.

Moreover, in selecting the discount rates used for the SCC Estimates, OMB disregarded explicit instructions from Congress, embodied in the Regulatory Right to Know Act, intended to guide the cost-benefit analysis of federal regulations. The Regulatory Right to Know Act requires OMB to issue standardized guidelines to federal agencies on the measurement of costs

⁴⁷ *Final Information Quality Bulletin for Peer Review* at 12.

⁴⁸ *Id.* at 7 (emphasis added).

⁴⁹ 2010 TSD at 19.

and benefits. These guidelines are to be subjected to external peer review. Circular A-4 represents the current version of these guidelines and includes a discussion of the best practices to be used for applying discount rates to future benefits and costs:

As a default position, OMB Circular A-94 states that a real discount rate of 7 percent should be used as a base-case for regulatory analysis. The 7 percent rate is an estimate of the average before-tax rate of return to private capital in the U.S. economy. It is a broad measure that reflects the returns to real estate and small business capital as well as corporate capital. It approximates the opportunity cost of capital, and it is the appropriate discount rate whenever the main effect of a regulation is to displace or alter the use of capital in the private sector. OMB revised Circular A-94 in 1992 after extensive internal review and public comment. In a recent analysis, OMB found that the average rate of return to capital remains near the 7 percent rate estimated in 1992. Circular A-94 also recommends using other discount rates to show the sensitivity of the estimates to the discount rate assumption.⁵⁰

Circular A-4 also allows “a further sensitivity analysis using a lower but positive discount rate” when a rule “will have important intergenerational benefits or costs,” but requires that the 7% rate be used for the base-case analysis.⁵¹

By selecting discount rates lower than prescribed by current OMB guidelines, and failing to subject the change in discount rates to the external peer review process, OMB has failed to follow the procedures mandated by Congress in the Regulatory Right to Know Act.

These comments do not advocate for use of a particular discount rate. Rather, consistent with the emphasis throughout these comments on process, the Associations similarly urge OMB and the federal government generally to pursue an open process – with full disclosure of information and how various factors and considerations are weighed – regarding the selection of an appropriate discount rate for use in development of the SCC Estimates. As Cass Sunstein, former head of OIRA/OMB, recently remarked:

Reconsideration of existing judgments must be subjected to a demanding and time-consuming process of internal review (and potentially to external review as well). Institutional constraints, including the need to obtain consensus, can

⁵⁰ OMB Circular A-4 at 33 (emphasis added).

⁵¹ *Id.* at 36 (“If your rule will have important intergenerational benefits or costs you might consider a further sensitivity analysis using a lower but positive discount rate in addition to calculating net benefits using discount rates of 3 and 7 percent.”). A 3% rate is prescribed “when regulation primarily and directly affects private consumption (e.g., through higher consumer prices for goods and services),” a scenario that is not primarily implicated with respect to the SCC.

impose obstacles to efforts to rethink existing practices, especially in an area like discounting, which is at once technical and highly controversial.⁵²

Mr. Sunstein argues for caution in revisiting the discount rates used by the IWG for the SCC Estimates. The need for such caution is appropriate, but also underscores the importance of subjecting departures from existing federal guidelines to proper scrutiny and an open and transparent process. In departing from the discount rates prescribed by Circular A-4, the IWG and OMB process should and must be subjected to public comment and peer review to allow proper vetting of the choice of this “technical and highly controversial” factor.

IV. THE BROAD RANGE OF SCC ESTIMATES GENERATED BY THE COMPUTER MODELING SYSTEMS MAKES THEM UNSUITABLE FOR USE IN RULEMAKING AND POLICY DECISIONS

Predicting the future in terms of impacts stemming from the emission of GHGs, as one might expect, is a massively imprecise exercise reliant on assumptions, hypotheses, and judgments about future technological advances, principles, and decisions that directly impact emissions scenarios, mitigation, and adaptation. While the undersigned Associations support the use of economic modeling, there are limits to the effectiveness of certain modeling techniques. For instance, the imprecision inherent in modeling assumptions, hypotheses, and judgments are significantly magnified when impacts (and costs) are projected over a longer time period. While certainty is not a characteristic of any modeling effort, OMB and the IWG cannot push prognostications so far beyond the capabilities of current science and economic modeling that the estimates become little more than guesswork. There is a threshold beyond which uncertainties become so profound, widespread, and compounded that, when further undermined by data limitations and the inherent limitations of the models, render the ultimate estimate flawed and unusable. Even the Intergovernmental Panel on Climate Change (“IPCC”) limits its future climate predictions and presents a range of possible scenarios (*see infra* §IV.B).

In the OMB IQA Response, OMB seems to acknowledge that such a tipping point exists whereby data are so uncertain they render the ultimate estimate unusable, and that “[i]n the absence of quantitative estimates, we would use a qualitative description of the types of impacts on society that we would expect.”⁵³ OMB further stated that, “[i]t is not clear to us, however, how the SCC estimates would be near such a threshold.”⁵⁴ While the Associations welcome OMB’s acknowledgement that a threshold exists where quantitative estimates become unworkable, we do not share OMB’s view that impacts predicted in 2300 are not yet “near such a threshold.”

⁵² Sunstein, Cass, “On Not Revisiting Official Discount Rates: Institutional Inertia and the Social Cost of Carbon” (2014) (draft) (forthcoming in *American Economic Review: Papers and Proceedings*).

⁵³ OMB IQA Response at 4.

⁵⁴ *Id.*

Significantly, the 2010 TSD appears to be somewhat in agreement with the Associations on this point. After noting extensively the “uncertainty, speculation, and lack of information” on key inputs necessary to estimate the SCC, the TSD disclaims that “[t]he purpose of the SCC estimates presented here is to make it possible for agencies to incorporate the social benefits from reducing carbon dioxide emissions into cost-benefit analysis of regulatory actions that have small, or ‘marginal,’ impacts on cumulative global emissions.”⁵⁵ Again, the Associations do not endorse the notion that the SCC Estimates are useful for even “marginal” regulatory actions, but we concur with the 2010 TSD’s apparent conclusion that the SCC Estimates have limited utility in rulemaking. To the extent that the OMB IQA response is articulating OMB’s new position that these highly uncertain SCC Estimates have broad utility in all types of regulatory decisions, the Associations urge OMB to either reconsider, or provide some support in the record, for this new conclusion.

Further, that the 2013 SCC Estimates increased by 60 percent from the previous estimate developed only a few years prior (and, once again, within six months of publication) using the same set of models demonstrates that this exercise is massively uncertain and not sufficiently robust for policymaking. That degree of variability over the short term (2010-2013) should give OMB and the IWG pause and a heightened concern that estimating the SCC with a level of accuracy suitable for policymaking is perhaps beyond the capabilities of the model systems utilized.

Importantly, a subset of the Associations made a similar point in their IQA petition (before the SCC Estimate changed for the second time in 2013), to which OMB responded that this variability was a “reflection of the rapid pace of ongoing research on a topic of profound interest to the scientific community . . . and that rapidly evolving scientific understanding makes it more important, not less, to review and update the estimates on a periodic basis.”⁵⁶ The Associations believe that OMB misinterpreted the nature of our concern over the degree of “variability over the short term.” We fully agree that scientific understanding of these issues is “rapidly evolving” and changing based on “the rapid pace of ongoing research,” but we do not understand why OMB fails to view these frequent and fundamental changes in scientific understanding as evidence that the estimates are highly uncertain. If the scientific understanding is in flux, then the conclusions derived from that scientific understanding are *per se* uncertain.

A. Model(s) Structure And Damage Functions

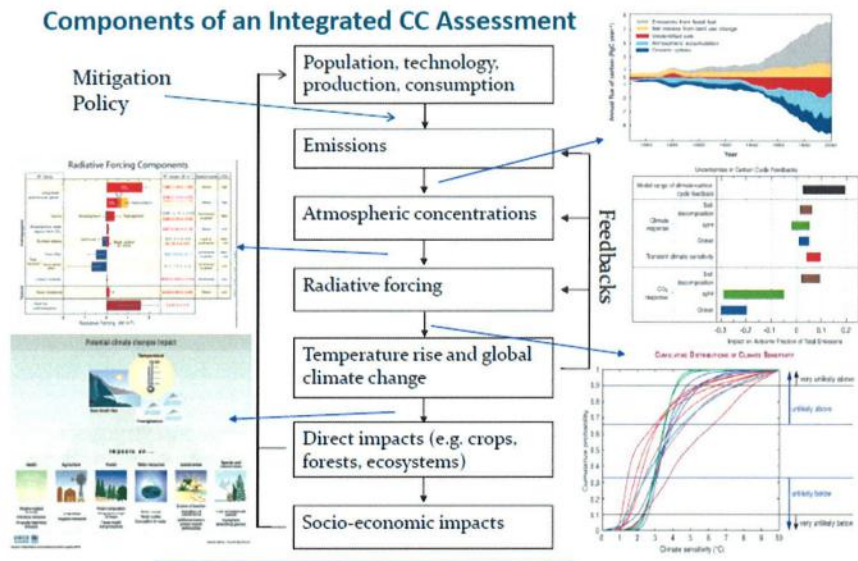
OMB and the IWG rely on three models which purport to predict the ultimate costs of a long chain of impacts stemming from the emission of GHGs (*i.e.*, the impact of temperature on sea-level rise, the impact of sea-level rise on waterside cities, the monetization of the impacts on waterside cities, *etc.*). These models have a similar “stacked” structure, shown in the figure below.⁵⁷ These models do not provide a detailed representation of the impact that climate

⁵⁵ 2010 TSD at 4-5.

⁵⁶ OMB IQA Response at 5.

⁵⁷ Taken from a presentation by Traeger, C., *The Economics of Climate Change*.

change may have on health, the environment, or the (global or domestic) economy, particularly at the regional or local levels.



The models on which the IWG relied utilize simplifying assumptions and judgments reflecting the modeler’s attempts to aggregate the available scientific and economic research characterizing these relationships. In particular, the “damage functions” used in these models simply reflect a guess about the relationship between changes in temperature and GDP. The record does not reflect an adequate scientific or factual basis for the “damage function” in any of the models upon which the government relies. As a result, the SCC Estimates are plagued by a high level of uncertainty that spans several orders of magnitude. The final socioeconomic impact prediction at the end relies on the cascading series of uncertain inputs in the prior steps. Model uncertainty, at any stage, is affected and magnified by all of the uncertainties in the prior steps (including model input and structure uncertainties, as well as the uncertainties of climate science), and the uncertainties associated with that particular step. This is especially true if socioeconomic outputs are predicted over very long time periods, as with the SCC Estimates.

Based in part on these compounded uncertainties, for the 2010 Estimates the authors noted that the IWG offered the new SCC values “with all due humility” about the uncertainties embedded in them and with a “sincere promise to continue work to improve them.”⁵⁸ In contrast, the 2013 SCC Estimates have done seemingly nothing to alleviate the uncertainty, but have nevertheless downplayed any discussion of that uncertainty. Only a small paragraph on “research gaps” is provided on the last page of the TSD for the 2013 SCC Estimates.

Other than a brief reference back to the 2010 SCC Estimates, the “humility” with which the estimates were originally provided has been lost. To our knowledge, modeling science has not made any quantum leaps in the intervening three years to merit this loss of humility. The

⁵⁸ 2010 Estimate at 29.

meager discussion of uncertainty in the most recent SCC Estimates promotes the unsupported and misleading idea that the updated SCC values are highly accurate figures.

The OMB IQA Response suggests that each subsequent iteration of the TSD (May 2013 and November 2013) should be viewed as having been appropriately discussed, uncertainty because those versions reference back to the 2010 TSD, which contained a more substantive discussion.⁵⁹ The Associations disagree. We believe it is important that wherever OMB presents changes to its SCC Estimates and the changes that lead to the amended estimate, it should provide a full discussion of the context for those estimates – including disclosing sources of uncertainty. Incorporating by reference a discussion of uncertainty buried 30 pages into a TSD issued multiple years and multiple versions previous makes it unnecessarily difficult for rule writers and regulators to view the SCC Estimates in the context of their profound uncertainty. Indeed, each of the subsequently issued TSDs utilize the same exact text as the 2010 TSD (except for those portions referencing the change in the estimate). The discussion of uncertainty, however, is uniquely shorthanded down to a reference to the 2010 TSD, in what seems like a calculated effort to split off the TSD’s discussions of the SCC estimates from the TSD’s discussions of uncertainty. While the easiest approach would be to leave the text in place when updating the TSD, it required an affirmative step to remove the uncertainty discussion and replace it with a shorthanded reference.

That there are key and substantial differences in the IAMs is not in dispute. The range of uncertainty across and within the two IAMs generating the lowest and highest average SCC estimate used by the IWG are demonstrated in Table 1 of the attached *NERA Damage Function Report*, reproduced here:

Table 1. Average SCC Estimates by Individual IAMs in IWG’s Analysis^(*)
 (\$/ton for emissions in 2020)

Discount Rate	Lowest Average SCC Estimate (from FUND)	Highest Average SCC Estimate (from PAGE)	Ratio of Highest to Lowest Average SCC
5%	\$3	\$22	8.3
3.0%	\$19	\$71	3.7
2.5%	\$33	\$101	3.1

^(*) The average dollar values were calculated by taking each model’s average SCC value across the IWG probability distribution of climate sensitivity values for each of the five IWG socioeconomic scenarios, and taking a simple average of those five values. They have been rounded to the nearest dollar. The ratios are based on the unrounded averages. The underlying data to compute these averages are in Appendix A of IWG (2013b), Tables A2-A4. In each case, the DICE estimate is the middle value, hence not affecting the range; DICE’s average values are \$12, \$38 and \$57 for the 5%, 3% and 2.5% discount rates, respectively.

This range of values reflects the average model estimates across five baseline input assumptions (and the probability distribution for climate sensitivity), and is presented for the three discount rates used in the IWG report. These results indicate a wide range of SCC values across the two models. Holding constant the other variables that the IWG standardized across the three models,

⁵⁹ OMB IQA Response at 5-6.

the average SCC estimates from the two models differ by a factor of 3 to 8, depending on the discount rate.

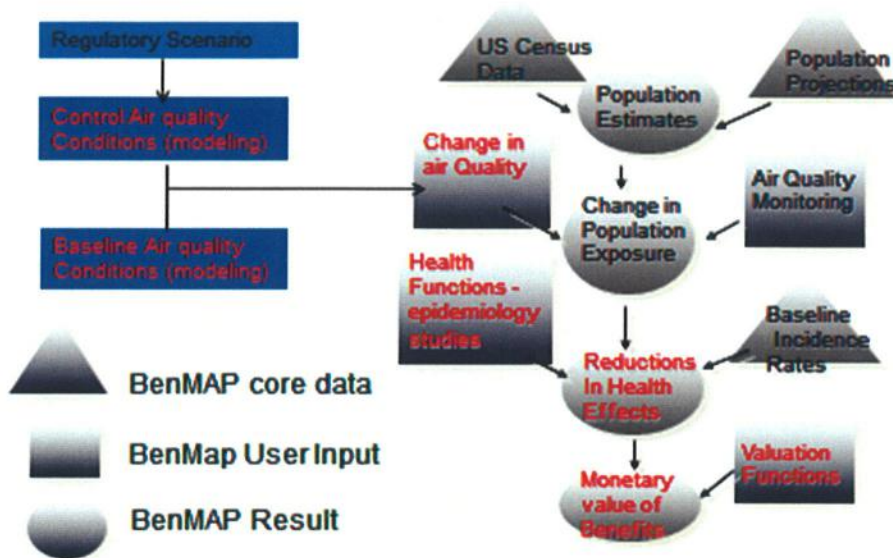
Given the degree of standardization already applied to the model input assumptions, these variations are substantial. The reasons for these variations are numerous. A considerable source of uncertainty and variability with the IAMs, not addressed by the IWG, is the “damage function” component of the models.⁶⁰ In fact, the NERA report suggests that the range of potential SCC values based upon uncertainties in the damage function is even larger than the structural variations across the DICE, FUND and PAGE models. This variability is because the formulation and utilization of the damage function in the three models are *ad hoc* and arbitrary, lack any theoretical or empirical foundation, and depend crucially on the views of the individual model builders.

The damage function is the point in the flow of computation within an IAM where the focus shifts from scientific relationships to economic relationships. Damage functions translate variables, such as projected sea level rise, to estimated economic damages. The simplified “damage function” approach used for the IAMs contrasts significantly with the traditional approach, used by EPA and others, to estimate the economic impact of pollutant emissions. Under the traditional approach, the available scientific evidence is evaluated to identify health and environmental effects deemed to be caused by the emitted pollutants. Concentration response functions are developed to define the frequency of the effects expected to result from exposure to the pollutant at varying concentrations. Finally, the estimated health and environmental effects are monetized using a valuation methodology. The following figure is adapted from EPA’s regulatory analysis for the final revisions to the National Ambient Air Quality Standards for Particulate Matter.⁶¹

⁶⁰ For a detailed analysis of the critical role of “damage functions” in the development of the SCC Estimates, and how treatment of the damage function in the IAMs contrasts with traditional regulatory impact analysis, see the attached *Damage Function Report*.

⁶¹ EPA-452/R-12-005 (Dec. 2012). Importantly, the Associations do not herein suggest that EPA’s analysis for PM NAAQS was accurate or appropriate. Instead, we are merely pointing out that EPA’s approach to assessing and monetizing damage from pollutants provides far more detail and a more tangible and supported connection between the pollutant at issue and the damage presumed therefrom.

The EPA Benefits Mapping and Analysis Program (BenMap) <http://www.epa.gov/air/benmap>



In contrast to this traditional approach to damage functions, the “damage function” of the IAMs utilized by the IWG neglects each of the traditional elements of a true damage function approach. To develop the SCC Estimates, the determination of the health, environmental, and physical damages attributed to GHG emissions is left to the authors of the IAMs, who translate these effects into an estimate of economic damage using a simple overall damage function of GDP versus temperature change. In doing so, the IWG defers to the model authors’ critical evaluations of the causal framework between GHG emissions and climate change impacts; the concentration-response function for various climate effects; and the monetization of those effects. Consequently, the subjective assumptions of the three model authors about the future can have great consequence to U.S. policy decisions.

The modelers recognize and readily concede the limitations of their models. Richard Tol, developer of the FUND model, admits that the result is not “a climate change impact model that is adequate. The accompanying static impact assessment is far from perfect, with many pieces missing and a lot of questionable assumptions.”⁶² William Nordhaus, developer of the DICE model, similarly states that “the damage functions continue to be a major source of modeling uncertainty.”⁶³ According to a well-known economist, “developers of IAMs can do little more than make up functional forms and corresponding parameter values. And that is pretty much

⁶² Tol, R. S., “Estimates of Damage Costs of Climate Change – Part 2: Dynamic Estimates,” *Environmental and Resource Economics*, 21:135-160, at 136 (2002).

⁶³ Nordhaus, W., *A Question of Balance*, New Haven: Yale University Press, at 51 (2008).

what they have done. . . . The bottom line here is that the damage function used in most IAMs are completely made up, with no theoretical or empirical foundation.”⁶⁴ Nordhaus similarly stated that the damage function analysis “involves the economic impacts of climate change, which is the thorniest issue in climate-change economics. These estimates are indispensable for making sensible decisions about the appropriate balance between costly emissions reductions and climate damages. However, providing reliable estimates of the damages from climate change over the long run has proven extremely difficult.”⁶⁵

There are numerous examples of the arbitrary outcomes created by the subjective judgment-based damage functions in the IAMs. For example, one of the key differences in the IAMs is the degree to which adaptation is considered to occur. FUND considers a significantly higher degree of adaptation to occur than DICE or PAGE. Similarly, each of the models considers the impact of catastrophic events in sharply dissimilar ways.

The variability and arbitrariness of the parameters that define the judgment-based damage functions can lead to profoundly different GDP impacts. For example, the *Damage Function Report* finds that the estimates of global damages due to a given temperature change can differ substantially depending upon the parameters of the presumed damage function.⁶⁶ The quantitative importance of the choice of damage function parameters is illustrated by considering the estimate of global damages when just two damage function parameters are varied from the lowest to the highest values for each that are discussed in the IAM literature. The figure below graphs the values that these four different damage functions would project at temperature changes up to 15°C. The sensitivity of results over this wide range of temperature change is shown because temperature changes up to 13°C may have been projected in some of the IWG’s IAM runs by the later end of the modeling period, the year 2300.

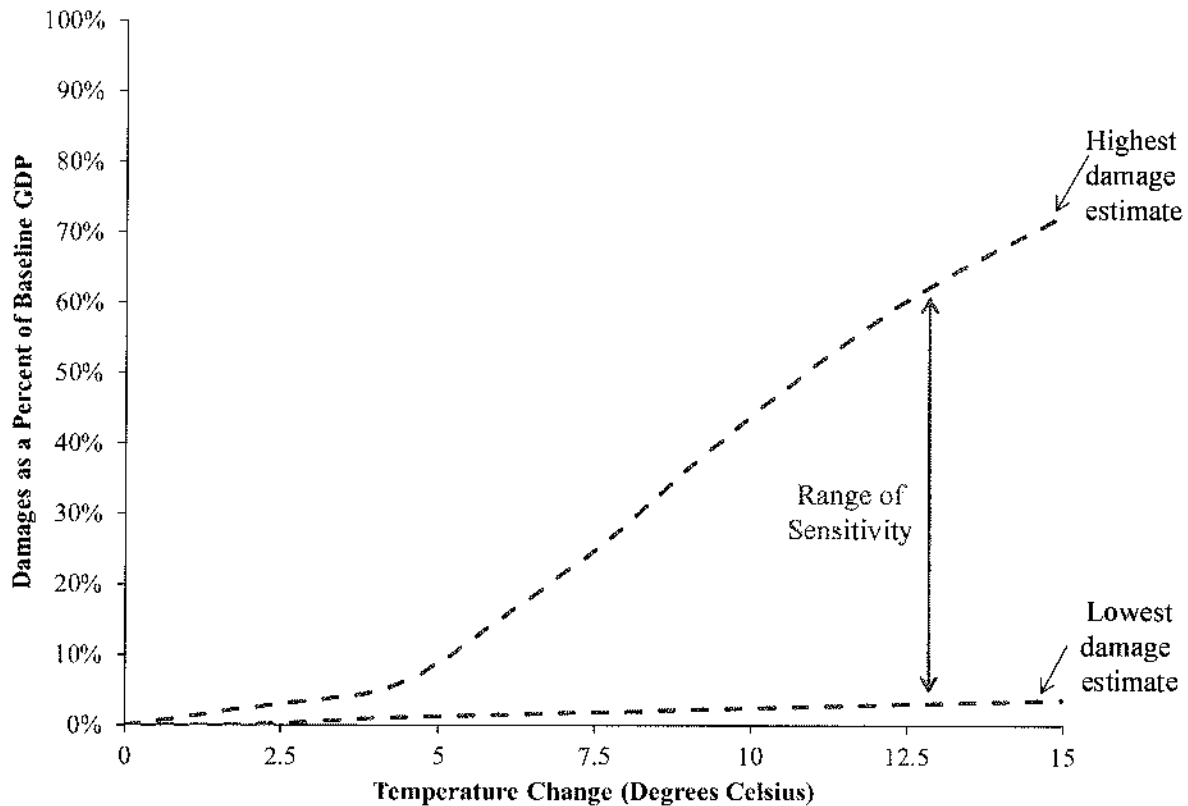
The sensitivity analyses show that the magnitude of the difference depends upon the level of temperature change, with the sensitivity greater at higher temperature changes. Although the large temperature changes are not important in the near term years of the projections, these temperature changes can be relevant in the later years of the projections.

⁶⁴ Pindyck, R.S., “Climate Change Policy: What Do the Models Tell Us?,” NBER Working Paper Series, WP 19244, at 11, 13 (July 2013) (Attachment 4).

⁶⁵ Nordhaus, W, *et. al.*, “DICE 2013: Introduction and User’s Manual,” at 10 (May 2013).

⁶⁶ *Damage Function Report* at 3-4.

Range of Damage Estimates with Variations in Two Damage Function Input Assumptions



According to the 2013 TSD, the larger SCC values reflect only changes made to the underlying IAMs. Directionally, all of the changes appear to be towards higher impacts. For the DICE model, the primary changes relate to the explicit representation of sea level rise (“SLR”) and associated damages and an updated calibration of the carbon cycle. The primary changes in the FUND model are updated damage functions for space heating, SLR agricultural impacts, changes to transient response of temperature buildup of GHG concentrations, and inclusion of indirect climate effects of methane. For PAGE, the key changes mentioned were explicit representation of SLR damages, revisions to damage functions to ensure damages do not exceed 100% of GDP, changes to regional scaling of damages, revised treatment of potentially abrupt damages, and some updated assumptions on adaptation.

Importantly, nothing in the IWG’s TSD effectively captures the arbitrary nature of how the updated IAMs have repeatedly changed the SCC estimates. For example, the authors of the DICE model claim the key damage function they used was based on a study by Tol (2009).⁶⁷ However, the Tol (2009) study indicates that up to a temperature rise of 2° C, climate change results in an *increase* in GDP.⁶⁸ In contrast, the damage function used in DICE presents a

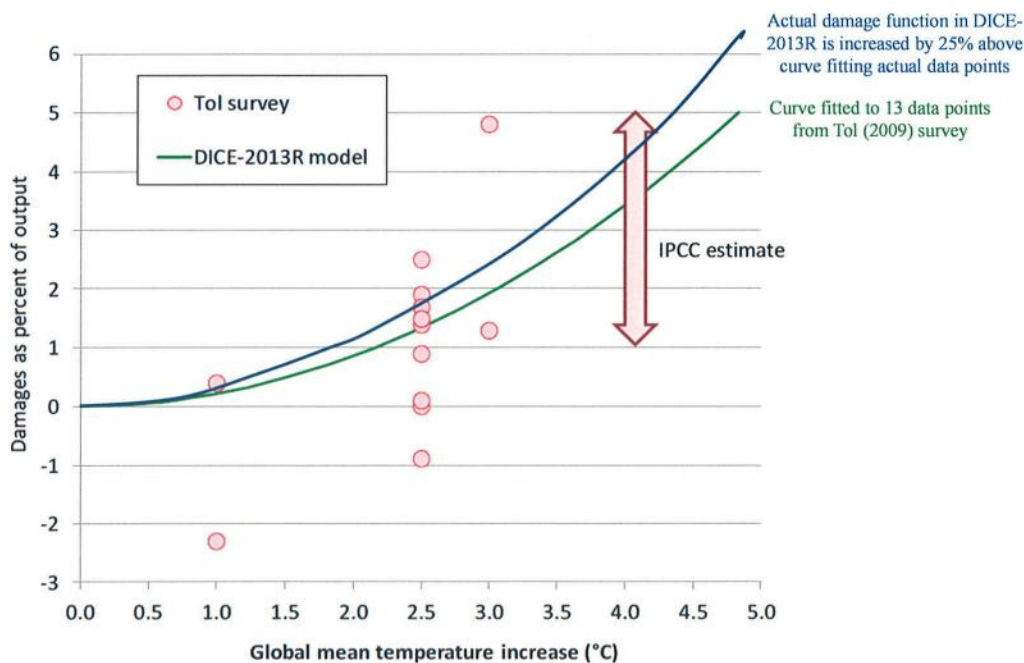
⁶⁷ This study is cited because it was used in or cited by models utilized for the TSD. The Associations are not endorsing this study or data to the exclusion of other information.

⁶⁸ See figure on page 18 in Tol (2009).

negative GDP change across all temperature changes considered. It is not clear how the authors of DICE altered the damage function presented in Tol (2009) or what the scientific basis was for this significant change.

Furthermore, the 25% increase in monetary value coming out of the updated 2013 DICE model was not produced by the IAM itself. Rather, the lead author, William Nordhaus, added an adjustment of 25% to the monetary damages to adjust for certain factors, including biodiversity, ocean acidification, and sea level rise.⁶⁹ See the figure below for the results of the survey conducted by Tol (2009), the DICE model's summary of that survey and the impact of the 25% adjustment. As the figure shows, for an assumed 4° C increase in global mean temperature rise, DICE predicts "damage" at the very high-end of the range that the IPCC projects. While the factors considered by Norhaus are certainly worthy of potential consideration to include in an evaluation of the SCC, the arbitrary nature by which the 25% increase in monetary value was assigned is troubling – estimates of economic damages should be scientifically derived, not assigned by one individual because those adjustments can have significant impacts on the output from the models.

Figure: DICE-2013R Damage Function (Before And After Adjustment)



Source: Nordhaus and Sztorc, "DICE-2013R: Introduction and User's Manual," Oct 2013. (Blue curve added to Nordhaus' figure by NERA to show damage function with the 25% adder assumed by Nordhaus to reflect non-monetized effects.)

⁶⁹ See Attachment 3

Similarly, the increase in the SCC in the PAGE model is based largely on the opinions of the authors as described in Hope (2011). In the updated PAGE2009 model used to derive the 2013 SCC figures, the authors assume far less adaptation will occur in response to climate change than they previously assumed. However, the authors cite no references to support this change. Nonetheless, this single change in assumption results in a 1.3-fold increase in the SCC versus the projections from PAGE2002. Another key change was how transient climate response (“TCR”), one of several components of climate sensitivity, was considered. To illustrate the importance of this one factor, a change in one standard deviation of the TCR can increase the SCC by 67%. In PAGE2009, a different triangular distribution of the TCR function was used than in PAGE2002. This resulted in a 1.5-fold increase in the SCC.⁷⁰ Further, in PAGE2009, the possibility for a catastrophic outcome or “discontinuity” above a fixed temperature threshold due to climate change was increased to 10% from the 1% used in PAGE2002. No documentation was provided to support these changes.

Subjective and arbitrary “adjustments” are troubling because those adjustments can have significant impacts on the output from the models. For example, compare the DICE damage function with that estimated by the IPCC, as shown in the figure above. For an assumed 4° C increase in global mean temperature rise, as the figure shows, DICE predicts “damage” at the very high-end of the range that the IPCC projects. Therefore, the inputs from DICE into the predicted SCC Estimates are biased extremely high relative to the IPCC estimated range of damages.

Ultimately, the authors of the *Damage Function Report* concluded:

[A]lthough the mathematical form of the damage function is relatively simple, plausible parameters for this mathematical formulation lead to very different estimates of global damages. We find, for example, that possible damage estimates at a given point in time can differ by up to a factor of 20 within the range of parameters and range of temperature changes found in the IAM literature. . .

The large degree of uncertainty regarding the damage function has implications for the uncertainty in the SCC values developed by the IWG. A comprehensive representation of damage function uncertainties – analyzed in combination with the other IAM input uncertainties – is needed to characterize how much more uncertain the IWG’s SCC estimates would be as a result of that damage function uncertainty. The IWG did not conduct such an analysis. Since the damage estimate is a central input to the ultimate SCC estimate, the large uncertainty in the damage function translates into uncertainty in the estimates of the social cost of carbon that may be correspondingly large.⁷¹

⁷⁰ We note that use of a crude triangular distribution for this key climate sensitivity factor itself is a reflection of the high degree of guesswork involved in the estimation of this factor.

⁷¹ *Damage Function Report* at 36-37.

Indeed, the SCC calculations in the DICE, FUND and PAGE models are the product of a highly simplified and aggregated formulation of the detailed calculations of climate science that goes directly from projected change in temperature to economic loss stated as change in GDP.⁷² The IWG acknowledges the consequences of the use of such models:

These models are useful because they combine climate processes, economic growth, and feedbacks between the climate and the global economy into a single modeling framework. At the same time, they gain this advantage at the expense of a more detailed representation of the underlying climatic and economic systems. DICE, PAGE, and FUND all take stylized, reduced form approaches. Other IAMs may better reflect the complexity of the science in their modeling frameworks but do not link physical impacts to economic damages.⁷³

As one expert noted to William Nordhaus (developer of the DICE model): “I marvel that they can translate a single number, an extremely poor surrogate for a description of the climatic conditions, into quantitative estimates of impacts of global economic conditions.”⁷⁴

B. Model Time Horizons

The 2010 and 2013 SCC Estimates are ambitiously projected for very long time horizons – specifically, until 2300.⁷⁵ The 2013 TSDs note that the DICE model, for example, can be run for an even longer time horizon (until 2595). The ability of any of these models (and their input assumptions) to hold for three centuries or more is not clear and certainly not verifiable. That the SCC Estimates increased 60 percent and changed three times in three years provides sufficient evidence to question the viability and usefulness of modeling that purports to render predictions nearly 300 years into the future. Incorporation of climate-affecting inputs – such as population changes, economic development, consumption patterns (regional and global), and technological advancements for mitigation (including the role of innovation and disruptive technologies) – as well as material stochastic variables, such as volcanic eruptions that can affect the underlying climate-forcing functions of GHG concentrations and temperature rise, over such time frames rely on identifying empirical relationships imbued with significant uncertainties. If we were to consider back to the year 1713, who could have predicted where the world is today?

Based on these key variables and uncertainties, IPCC does not attempt predictions beyond the year 2100.⁷⁶ Among other reasons, this constraint is due to the widely predicted

⁷² See NERA *Damage Function Report* at 10-14. The NERA report discusses in detail how the “damage function” component of the IAM models is a highly simplified approach to the traditional “damages function method” in which economic assessments are narrowly confined to valuing a specific set of projected adverse effects.

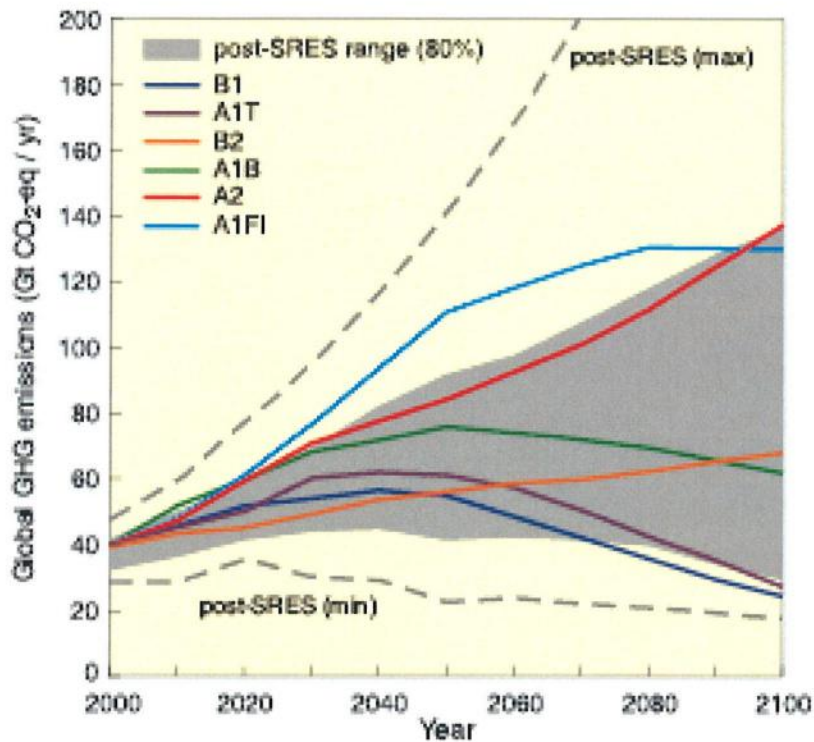
⁷³ 2010 TSD at 5.

⁷⁴ Nordhaus, W., “Expert Opinion on Climatic Change,” *American Scientist*, 82:45-51 (1994).

⁷⁵ 2013 Estimate at 7.

⁷⁶ See www.ipcc.ch/publications_and_data/ar4/syr/en/mains3.html. This reference should not be viewed as an endorsement of the IPCC’s conclusions, but rather as a reference point from which to compare the three models used in the SCC Estimates. The Fish and Wildlife Service & National Marine Fisheries Service often limit their modeling of potential climate impacts on species to even shorter time horizons.

variances in critical inputs, such as predicted model emissions. For example, the figure below, taken from the most recent IPCC work, shows how wide the emission predictions from various scenarios are, through just the year 2100.



As the authors of the *Damage Function Report* state:

[I]n the case of climate change, many of the impacts are very far in the future (up to 300 years hence, in the case of the IWG analyses), and also highly variable in terms of the region affected. Thus [condensing projections of economic damages across many years and regions into a single present-value global measure of welfare] raises issues regarding inter-generational and inter-regional equity that seem largely ethical rather than economic.⁷⁷

Clearly, attempting to extrapolate SCC Estimates to 2300 is simply too speculative and uncertain for use in policymaking.

V. CONCERNS WITH THE PRESENTATION OF THE SCC ESTIMATES

In addition to the Associations' concerns with opacity and accuracy of the modeling and SCC estimation process, we are further concerned that OMB and the IWG present the SCC Estimates in a confusing and potentially misleading manner. Failure to present this information

⁷⁷ *Damage Function Report* at 12.

in a way that appropriately identifies (and quantifies) uncertainty, neglects to explain the use and impact of averaging, and focuses on the global, rather than domestic, SCC, diminishes the utility of the SCC Estimates and increases the likelihood that they will be misused or misinterpreted by risk managers.⁷⁸

A. Uncertainty Is Not Addressed Appropriately

While there is no requirement that the SCC Estimates be absolutely precise and accurate, OMB's Circular A-4 requires key uncertainties to be disclosed and quantified to the extent possible "to inform decision makers and the public about the effects and uncertainties of alternative regulatory actions."⁷⁹ Circular A-4 requires uncertainties to be analyzed qualitatively and quantitatively, delineated, and disclaimed.⁸⁰ Further, OMB's Circular A-4 admonishes that:

Your estimates cannot be more precise than their most uncertain component. Thus, your analysis should report estimates in a way that reflects the degree of uncertainty and not create a false sense of precision. Worst-case or conservative analysis are [sic] not usually adequate because they do not convey the complete probability distribution of the outcomes, and they do not permit calculation of an expected value of net benefits.⁸¹

Rather than appropriately quantifying and disclaiming the profoundly speculative nature of the SCC Estimates, the IWG downplays the wide variability in the three models' outputs through averaging. Similar to the 2010 Estimates, the 2013 Estimates are based on the average outputs of the three models. Individual model predictions, however, vary significantly. For example, at a 3% discount rate, the cost per ton varies from a high of \$71/ton for PAGE to a low of \$21/ton for FUND, with the DICE estimate between these two costs at \$38/ton. This is shown in the table below.⁸²

⁷⁸ As detailed in the attached comments submitted by many of the undersigned Associations, problems with the implementation of the SCC Estimates by federal agencies in rulemakings already have been identified with regard to several proposed rulemakings, including DOE's proposed energy efficiency standards for metal halide lamps, walk-in coolers and freezers, and commercial refrigeration equipment. *See, e.g.*, Comments submitted October 12, 2013 by the Associations on DOE's Proposed *Energy Conservation Standards for Metal Halide Lamp Fixtures* (77 Fed. Reg. 51,563 (Aug. 20, 2013)); Comments submitted November 12, 2013 by the Associations on DOE's Proposed *Energy Conservation Standards for Walk-In Coolers and Freezers* (78 Fed. Reg. 55,782 (Sept. 11, 2013)); Comments submitted October 12, 2013 by the Associations on DOE's Proposed *Energy Conservation Standards for Commercial Refrigeration Equipment* (78 Fed. Reg. 55,890 (Sept. 11, 2013)); Comments submitted January 23, 2014 by Associations on Notice of Proposed Rulemaking for Energy Conservation Standards for Residential Furnace Fans 78 Fed. Reg. 64,067 (Oct. 25, 2014)); and Petition for Reconsideration filed by Associations on September 16, 2013 of Standards for Standby Mode and Off Mode for Microwave Ovens (78 FR 36316 (June 17, 2013)). These comments are attached (Attachment 5) and hereby incorporated by reference.

⁷⁹ OMB Circular A-4 at 38.

⁸⁰ *Id.* at 40.

⁸¹ *Id.* at 40.

⁸² November 2013 TSD at 21, Table A5.

Table A5: Additional Summary Statistics of 2020 Global SCC Estimates

Discount rate:	5.0%				3.0%				2.5%			
Statistic:	Mean	Variance	Skewness	Kurtosis	Mean	Variance	Skewness	Kurtosis	Mean	Variance	Skewness	Kurtosis
DICE	12	26	2	15	38	409	3	24	57	1097	3	30
PAGE	22	1616	5	32	71	14953	4	22	101	29312	4	23
FUND	3	560	-170	35222	21	22487	-85	18842	36	68055	-46	13105

While the differences in the “average” values between the models (a factor of ~3.5 between \$21/ton from the FUND model to \$71/ton from the PAGE model) are problematic enough, the predicted model variances are even more striking, as shown in the table above. For example, it is simply meaningless to predict a “mean” of \$21/ton based on FUND, when the corresponding variance is predicted to be \$22,487. The same is true for each of the other predictions.

This broad range reflects not only the effects of the various inputs and model structure uncertainties, but also the impact of taking the *average* of the three models for the five climate change scenarios at the four discount rates used in the SCC development analysis. The average values are much higher than the 50th percentiles for all three models, but are particularly higher than the 50th percentile figure in the case of the PAGE model.

Using the 3% discount rate as an example, the average values per ton versus the 50th percentile values per ton for the PAGE, DICE, and FUND models are \$71/\$27, \$38/\$34, and \$21/\$17, respectively. Therefore, for the PAGE, DICE, and FUND models, the value used to derive the final SCC figure of \$43/ton at the 3% discount rate is the 75th percentile value for the PAGE model and the overall SCC value of \$43.1 per ton corresponds to the 68th percentile. Thus, the high-end tail of the distribution of the PAGE model has an important influence on the final SCC Estimates. These final SCC Estimates should not be viewed as central figures, but rather as skewed toward the upper tail of the distribution of SCC values. Indeed, there is no rational basis for “averaging” the results, on an equally-weighted basis, from the three IAM models, which differ significantly in the assumptions they use to estimate SCC. Rather than make an effort to determine which of the three models provides the best estimates, the government instead combines all of the estimates and divides to obtain a simple average.

OMB must adhere to the directives it imposes on other agencies and executive offices with respect to providing accurate information. It has not done so with the SCC Estimates. The IWG and OMB have failed to disclose and quantify key uncertainties and to inform fully decision makers and the public of those uncertainties as required by OMB. Consistent with OMB Guidelines for Economic Analysis, the 2013 TSD must be withdrawn and amended to include a separate section that identifies the key sources of uncertainty in the derivation of the SCC. This section should include a qualitative assessment of the impact of key factors on the final SCC values and, to the extent feasible, a quantitative assessment of these factors.

B. By Presenting Only Global SCC Estimates, The IWG Severely Limits The Utility Of The Estimates For Use In Cost-Benefit Analysis And Policymaking

OMB's IQA Guidelines require that information disseminated by agencies meet the standard of utility. This part of the IQA requires agencies to assess the usefulness of the information to its intended users, including the public. For the 2013 Estimates, by presenting only global SCC estimates, and excluding domestic SCC estimates altogether, the IWG severely limits the utility of the SCC Estimates for use in cost-benefit analysis.

Further, OMB Circular A-4 mandates calculation of a domestic cost-benefit estimate in federal rulemakings, with non-U.S. estimates considered as *optional* – the reverse of the presentation published by IWG/OMB. Moreover, neither the May 2013 TSD, nor the November 2013 TSD mention the global nature of the values or note that the domestic SCC is a small fraction (7-23%) of the global SCC. Thus, policymakers who apply the SCC values from this table and have not read the previous 2010 TSD may be unaware that a large percentage of the economic benefits they are estimating from their rule will occur outside the United States.⁸³

The IWG's recommendation that rule writers and policymakers use only the global SCC in cost-benefit analysis results in a significant misalignment of costs and benefits. For this reason, we strongly recommend presenting both the domestic and global SCC figures in RIAs, with a preference for use of the domestic values. This approach would allow risk managers to more readily align the costs with the benefits. Consistent with OMB guidance, the costs of a rule for entities in the United States should be presented in comparison with the benefits occurring in the United States. The benefits using the global SCC should be presented separately. Along with the global SCC benefits, federal agencies proposing a rule should be encouraged to present at least a qualitative accounting of similar regulatory efforts underway or proposed in other countries for the specific type of problem their rule is proposed to address. This approach would meet the goal of Executive Order 13609 that federal agencies evaluate how rules they are proposing differ from requirements for key United States trading partners.

⁸³ For example, the 2010 TSD states:

As an empirical matter, the development of a domestic SCC is greatly complicated by the relatively few region- or country-specific estimates of the SCC in the literature. One potential source of estimates comes from the FUND model. The resulting estimates suggest that the ratio of domestic to global benefits of emission reductions varies with key parameter assumptions. For example, with a 2.5 or 3 percent discount rate, the U.S. benefit is about 7-10 percent of the global benefit, on average, across the scenarios analyzed. Alternatively, if the fraction of GDP lost due to climate change is assumed to be similar across countries, the domestic benefit would be proportional to the U.S. share of global GDP, which is currently about 23 percent.

On the basis of this evidence, the interagency workgroup determined that a range of values from 7 to 23 percent should be used to adjust the global SCC to calculate domestic effects. Reported domestic values should use this range.

We note that the approach of presenting only a global benefit value while comparing it to a domestic cost value is inconsistent with policies used in the United States to perform cost-benefit analysis for rules intended to address other significant environmental issues that are global in scope. For example, ground level ozone is now recognized by many as a health and environmental issue that is global in nature. Recent studies clearly demonstrate that emissions from the Asia Pacific region affect compliance with the United States NAAQS for ozone.⁸⁴ However, the current approach of performing cost-benefit analysis of air rules for NAAQS compliance purposes does not consider the global nature of the issue. Rather, the costs to comply with the NAAQS are borne entirely by entities in the United States and the damages of ozone are estimated without any recognition of the impact of the emissions from outside the continental United States.

The IQA Petition filed with OMB raised substantially similar concerns on the TSD's presentation of global impacts, to which the OMB IQA Response simply quoted from the 2010 TSD the justification for its presentation of global impacts.⁸⁵ OMB's recital of its earlier justification for its presentation of global impacts was not altogether responsive. The Associations are aware of the justification provided in the 2010 TSD, but disagree with it, find it inconsistent with OMB Circular A-4 and analogous regulatory actions with potential global impacts, and misleading to risk managers. We are herein requesting that OMB change this presentation.

VI. ADMINISTRATIVE PROCEDURE ACT

The Administrative Procedure Act's ("APA") broad definition of a "rule" includes "an agency statement of general or particular applicability and future effect designed to implement, interpret, or prescribe law or policy," such as "the approval or prescription of . . . valuations, costs, or accounting."⁸⁶ When promulgating a substantive rule, an agency must comply with the APA's procedural requirements by providing notice of proposed action describing its substance and the legal authority under which it is proposed, by allowing for public comment, and by including in the rule a description of its basis and purpose.⁸⁷ Agency rules are subject to judicial review and may be set aside if they are "arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law."⁸⁸

At the outset, we note that OMB identifies no authority under which it can adopt the SCC Estimates as a rule, or the statutory or regulatory basis for this proceeding. OMB's exercise of regulatory discretion without identifying explicit direction from Congress therefore raises serious

⁸⁴ Cooper O.R., et al. (2010). Increasing springtime ozone mixing ratios in the free troposphere over western North America. *Nature* 463(21): 344-348.

⁸⁵ OMB IQA Response at 6-7.

⁸⁶ 5 U.S.C. § 551(4); *see also Avoyelles Sportsmen's League, Inc. v. Marsh*, 715 F.2d 897, 908 (5th Cir. 1983) ("rule" includes "virtually every statement an agency can make").

⁸⁷ 5 U.S.C. § 553; *see id.* § 553(b) (only certain non-substantive rules exempted from procedural requirements).

⁸⁸ 5 U.S.C. § 706(2)(A).

constitutional concerns, including concerns about breaching the separation of powers between the legislative and executive branches and violating the non-delegation doctrine. If OMB nonetheless adopts the SCC Estimates presented in the TSD absent identification of clear statutory authority to do so, its action will be subject to challenge as unlawful rulemaking. In this regard, according to statements made by OMB, the SCC Estimates are intended to “prescribe law or policy” by specifying “valuations, costs, or accounting” to govern federal agencies’ analyses of the costs and benefits of their regulatory actions.⁸⁹ Indeed, many federal programs require that agencies consider the direct and indirect costs of proposed actions. For example, Exec. Order No. 12,866 states that agencies must “propose or adopt a regulation only upon a reasoned determination that the benefits of the intended regulation justify its costs.” And prior SCC estimates adopted by OMB have already influenced agencies’ consideration of regulatory costs, as was the case with the microwave oven efficiency standards and other rules. Because the SCC Estimates in this TSD are designed to constrain agency decision-making regarding how carbon costs are to be evaluated in future agency proceedings and because, once finalized, they are to be imposed across the federal government as a common cost valuation for carbon, this proceeding represents unlawful rulemaking. For these reasons and those discussed below, the proposed TSD fails to comply with the APA’s procedural and substantive requirements.

Additionally, use of the SCC Estimates in subsequent rulemakings will result in agency violations of the APA. Under the APA, a court will look to ensure that the information collection and analysis process is lawful and reasonably coherent, and that the ultimate agency action which results from use of that information is not arbitrary and capricious.⁹⁰

From a substantive perspective, an agency engaged in rulemaking must examine the relevant data and articulate a satisfactory explanation for its action, including a “rational connection between the facts found and the choice made.”⁹¹ Agency action is arbitrary and capricious “if the agency has relied on factors which Congress has not intended it to consider, entirely failed to consider an important aspect of the problem, offered an explanation for its decision that runs counter to the evidence before the agency, or is so implausible that it could not be ascribed to a difference in view or the product of agency expertise.”⁹²

Use of the SCC Estimates in rulemaking will violate the APA. For instance, the record does not show what roles each of the IWG participating agencies actually played in developing the estimates. The record does not show which staff from the participating agencies participated in the process. The record does not show how the three models that underlie these estimates were selected (from the universe of similar available models). The record does not show who ran the models (agency staff? contractors?) or their qualifications or level of expertise. The

⁸⁹ See, e.g., 78 Fed. Reg. at 70,586 (Through the SCC, OMB will “ensure that agencies are appropriately measuring the social cost of carbon emissions as they evaluate the costs and benefits of rules.”); OMB IQA Response (OMB seeks “public comment on the SCC through the formal public comment process that applies to all Federal rulemakings.”).

⁹⁰ See *Citizens to Preserve Overton Park, Inc. v. Volpe*, 401 U.S. 402 (1971).

⁹¹ *Motor Vehicle Mfrs. Ass’n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983).

⁹² *Id.*

record does not show who developed the inputs for the model runs, including both policy as well as technical choices, and it is not clear how such inputs were developed. The record does not show how the various statistical Monte Carlo analyses actually were implemented (which inputs were held constant and why, which inputs were selected to be variable and why, and the assumptions regarding the assumed distribution functions for the latter variable inputs, *etc.*). These are but a few of the flaws, uncertainties, and unknowns that should preclude the use of the SCC Estimates/TSD.

Each of these failures violates fundamental precepts of administrative procedure and the scientific method – and none credibly can be stated to be the result of a difference of opinion, interpretation, or Agency expertise. To the contrary, these are examples where the Administration drove its conclusions far beyond the capacity of sound science and modeling. Even if the three models themselves were entirely sound, the non-public inputs into those models most certainly render the model output (*i.e.*, the SCC Estimates) arbitrary and capricious.

APA's decision-making standards also demand compliance with the IQA, including requirements for complete, unbiased analysis grounded in accepted methods. "Determination of whether the agency complied with prescribed procedures requires a plenary review of the record and consideration of applicable law."⁹³ More specifically, the APA requires that agencies relying on SCC Estimates in rulemaking review all credible relevant information, utilize unbiased peer review, and make Agency assumptions, methods, and models transparent and reasonably reproducible and understandable in response to an appropriate request for information. If OMB allows or directs other agencies to use the SCC Estimates, any agency that bases a rule on these estimates would violate the IQA and the APA, and the legality of such regulation would be called into question. The ultimate rationality of subsequent agency action depends in part on whether it has thoroughly complied with applicable procedural requirements, including those set forth in the IQA.⁹⁴

VII. CONCLUSION

The Associations appreciate the opportunity to comment on the SCC Estimates. However, without the benefit of any of the information underpinning the SCC Estimates or any indication that OMB intends to actually consider comments, this process does little more than suggest, incorrectly, the appearance of transparency and collaboration. Given the significant process shortcomings, lack of peer review, and weaknesses and uncertainties in the modeling systems highlighted in these comments and related IQA Petition, the undersigned Associations

⁹³ See *Olenhouse v. Commodity Credit Corp.*, 42 F.3d 1560, 1574 (10th Cir. 1994).

⁹⁴ Even if a particular statute, such as the IQA, does not provide for judicial review, "the agency's decision may still be overturned because of an analysis so defective as to render its final decisions unenforceable, or, in the absence of any analysis, because of a failure to respond to public comment concerning" the legal infirmities identified pursuant to that statute. *Michigan v. Thomas*, 805 F.2d 176, 188 (6th Circuit 1986); *Thompson v. Clark*, 741 F.2d 401, 405 (D.C. Circuit 1984.) (The flawed rule "is set aside, ... not because the regulatory flexibility analysis [not subject to direct judicial review] was defective, but because the mistaken premise reflected in the regulatory flexibility analysis deprives the rule of its required rational support").

urge OMB and the IWG to withdraw the 2010 and 2013 Technical Support Documents, pending correction through an informed, transparent, and public process. OMB's November 26, 2013 solicitation of comments certainly is not such an informed, transparent, and public process. As such, we further ask OMB to refrain from using the SCC Estimates and to direct publicly other executive branch agencies not to utilize the SCC Estimates as part of any regulatory action or policymaking. Finally, as per the February 24, 2014 Request for Reconsideration of the OMB IQA Response filed by many of the Associations, and for the reasons noted throughout these comments, the Associations request that OMB reconsider its denial of the September 4, 2013 Petition calling on OMB to ensure that the SCC Estimates and TSD comply with IQA guidelines.

We appreciate the opportunity to submit the foregoing comments. If you have any questions or need any further information about these comments, please contact our counsel Wayne D'Angelo at 202.342.8525 or WDAngelo@Kelleydrye.com.

Respectfully submitted,

American Chemistry Council

American Coalition for Clean Coal Electricity

**American Exploration &
Production Council**

American Forest & Paper Association

**American Fuel & Petrochemical
Manufacturers**

American Iron and Steel Institute

American Petroleum Institute

America's Natural Gas Alliance

Brick Industry Association

Council of Industrial Boiler Owners

The Fertilizer Institute

Independent Petroleum Association of America

National Association of Home Builders

National Association of Manufacturers

Natural Gas Supply Association

National Mining Association

National Oilseed Processors Association

Portland Cement Association

U.S. Chamber of Commerce

Cc: Mabel Echols

Attachment 1 Statements of Interest

The American Chemistry Council: The American Chemistry Council (“ACC”) represents the leading companies engaged in the business of chemistry. ACC members apply the science of chemistry to make innovative products and services that make people's lives better, healthier and safer. ACC is committed to improved environmental, health and safety performance through Responsible Care®, common sense advocacy designed to address major public policy issues, and health and environmental research and product testing. The business of chemistry is a \$770 billion enterprise and a key element of the nation's economy. It is one of the nation’s largest exporters, accounting for twelve percent of all U.S. exports. Chemistry companies are among the largest investors in research and development. Safety and security have always been primary concerns of ACC members, and they have intensified their efforts, working closely with government agencies to improve security and to defend against any threat to the nation’s critical infrastructure.

The American Coalition for Clean Coal Electricity: The American Coalition for Clean Coal Electricity (“ACCCE”) is a trade association of more than 30 companies associated with the production of electricity from coal. ACCCE’s members span the production, transportation, and consumption of coal that has provided nearly half of the reliable electricity Americans depend upon each and every day over the past decade. ACCCE supports policies that will ensure affordable, reliable, domestically produced energy, while supporting the development and deployment of advanced technologies to further reduce the environmental footprint of coal-fueled electricity generation.

The American Exploration & Production Council: American Exploration & Production Council (“AXPC”) is a national trade association representing 32 of America's largest and most active independent oil and natural gas exploration and production companies. AXPC members are "independent" in that their operations are limited to exploration for and production of oil and natural gas. Moreover, our members operate autonomously, unlike their fully integrated counterparts, which operate in additional segments of the energy business, such as downstream refining and marketing. AXPC members are leaders in developing and applying the innovative and advanced technologies necessary to explore for and produce oil and natural gas, both offshore and onshore, from unconventional sources.

The American Forest & Paper Association: The American Forest & Paper Association (“AF&PA”) serves to advance a sustainable U.S. pulp, paper, packaging, and wood products manufacturing industry through fact-based public policy and marketplace advocacy. AF&PA member companies make products essential for everyday life from renewable and recyclable resources and are committed to continuous improvement through the industry’s sustainability initiative - Better Practices, Better Planet 2020. The forest products industry accounts for approximately 4.5 percent of the total U.S. manufacturing GDP, manufactures approximately \$200 billion in products annually, and employs nearly 900,000 men and women. The industry

meets a payroll of approximately \$50 billion annually and is among the top 10 manufacturing sector employers in 47 states.

The American Fuel & Petrochemical Manufacturers: The American Fuel & Petrochemical Manufacturers (“AFPM”) is a national trade association of more than 400 companies, including virtually all U.S. refiners and petrochemical manufacturers. AFPM members operate 122 U.S. refineries comprising approximately 98% of U.S. refining capacity. AFPM petrochemical members make the chemical building blocks which go into products ranging from medical devices, cosmetics, furniture, appliances, TVs and radios, computers, parts used in every mode of transportation, solar power panels and wind turbines. As an energy intensive industry, AFPM members are directly impacted by the government’s calculation of the social cost of carbon.

The American Iron and Steel Institute: The American Iron and Steel Institute (“AISI”) is a non-profit, national trade association headquartered in the District of Columbia. AISI serves as the voice of the North American steel industry in the public policy arena and advances the case for steel in the marketplace as the preferred material of choice. AISI represents member companies accounting for more than three quarters of U.S. steelmaking capacity.

The American Petroleum Institute: The American Petroleum Institute (“API”) is a national trade association representing over 500 member companies involved in all aspects of the oil and natural gas industry. API’s members include producers, refiners, suppliers, pipeline operators, and marine transporters, as well as service and supply companies that support all segments of the industry. API and its members are dedicated to meeting environmental requirements, while economically developing and supplying energy resources for consumers.

America’s Natural Gas Alliance: Representing North America’s largest independent natural gas exploration and production companies, America's Natural Gas Alliance (ANGA) works with industry, government and customer stakeholders to promote increased demand for our nation’s abundant natural gas resource for a cleaner and more secure energy future and to ensure its continued availability.

The Brick Industry Association : Founded in 1934, the Brick Industry Association represents the U.S. clay brick industry, which includes 270 manufacturers, distributors, and suppliers that provide employment for nearly 200,000 Americans in 44 states and historically generate approximately \$9 billion to the U.S. economy annually. Our members and our industry could potentially be needlessly harmed by this rulemaking. Given the large number of small businesses affected by this rule, including in the brick industry, additional time is justified.

The Council of Industrial Boiler Owners: The Council of Industrial Boiler Owners (“CIBO”) is a broad-based association of industrial boiler owners, architect-engineers, related equipment manufacturers, and University affiliates with members representing 20 major industrial sectors. CIBO members have facilities in every region of the country and a representative distribution of almost every type of boiler and fuel combination currently in operation. CIBO was formed in 1978 to promote the exchange of information within the industry and between industry and

government relating to energy and environmental equipment, technology, operations, policies, law and regulations affecting industrial boilers. Since its formation, CIBO has been active in the development of technically sound, reasonable, cost-effective energy and environmental regulations for industrial boilers. CIBO supports regulatory programs that provide industry with enough flexibility to modernize -- effectively and without penalty - the nation's aging energy infrastructure, as modernization is the key to cost-effective environmental protection.

The Fertilizer Institute: The Fertilizer Institute (“TFI”) represents the nation’s fertilizer industry including producers, importers, retailers, wholesalers and companies that provide services to the fertilizer industry. TFI members provide nutrients that nourish the nation’s crops, helping to ensure a stable and reliable food supply. TFI’s full-time staff, based in Washington, D.C., serves its members through legislative, educational, technical, economic information and public communication programs.

The Independent Petroleum Association of America: The Independent Petroleum Association of America (IPAA) is the national trade organization representing thousands of American oil and natural gas explorers and producers, as well as the service and supply industries that support their efforts. These businesses will be significantly affected by the proposed actions in this regulatory framework. IPAA member companies drill about 95 percent of American oil and natural gas wells, produce about 54 percent of American oil, and more than 85 percent of American natural gas.

The National Association of Home Builders: The National Association of Home Builders (“NAHB”) is a nationwide federation of more than 850 state and local home builder associations representing more than 140,000 members including individuals and firms engaged in land development, single and multifamily construction, multifamily ownership, building material trades, and commercial and industrial projects. More than 80 percent of NAHB members are classified as “small businesses” and meet the federal definition of a “small entity,” as defined by the U.S. Small Business Administration. The use of the Social Cost of Carbon report as a basis for future rulemakings will have a profound impact on the way homes and communities of the future will be built.

The National Association of Manufacturers: The National Association of Manufacturers (“the NAM”) is the largest industrial trade association in the United States, representing over 12,000 small, medium and large manufacturers in all 50 states. NAM is the leading voice in Washington, D.C., for the manufacturing economy, which provides millions of high wage jobs in the U.S. and generates more than \$1.6 trillion in GDP. In addition, two-thirds of NAM members are small businesses, which serve as the engine for job growth. NAM’s mission is to enhance the competitiveness of manufacturers and improve American living standards by shaping a legislative and regulatory environment conducive to U.S. economic growth.

The National Mining Association: The National Mining Association (“NMA”) is a national trade association whose members produce most of America’s coal, metals, and industrial and agricultural minerals. Its membership also includes manufacturers of mining and mineral

processing machinery and supplies, transporters, financial and engineering firms, and other businesses involved in the nation's mining industries. NMA works with Congress and federal and state regulatory officials to provide information and analyses on public policies of concern to its membership, and to promote policies and practices that foster the efficient and environmentally sound development and use of the country's mineral resources.

The National Oilseed Processors Association: The National Oilseed Processors Association ("NOPA") is a national trade association that represents 13 companies engaged in the production of vegetable meals and vegetable oils from oilseeds, including soybeans. NOPA's member companies process more than 1.6 billion bushels of oilseeds annually at 63 plants located in 19 states, including 57 plants that process soybeans.

The Natural Gas Supply Association: The Natural Gas Supply Association ("NGSA"), established in 1965, represents integrated and independent companies that produce and market approximately 40 percent of the natural gas consumed in the United States. NGSA encourages the use of natural gas within a balanced national energy policy and promotes the benefits of competitive markets to ensure reliable and efficient transportation and delivery of natural gas and to increase the supply of natural gas to U.S. customers.

The Portland Cement Association: The Portland Cement Association ("PCA") is the national trade association for the United States cement manufacturing industry. PCA's 26 member companies operate 79 manufacturing plants in 34 states, accounting for almost 80 percent of domestic cement manufacturing capacity. In 2011, the cement manufacturing and related industries generated nearly \$44 billion in annual revenues and supported more than 150,000 high quality manufacturing jobs in the United States.

The U.S. Chamber of Commerce: The U.S. Chamber of Commerce ("the Chamber") is the world's largest business federation representing the interests of more than 3 million businesses of all sizes, sectors, and regions, as well as state and local chambers and industry associations. The Chamber is dedicated to promoting, protecting, and defending America's free enterprise system.

ATTACHMENT G

April 7, 2014

VIA ELECTRONIC FILING AND ELECTRONIC MAIL

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Environmental Protection Agency
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1200 Pennsylvania Ave. NW
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RE: Docket ID No. EPA-HQ-OA-2014-0129; Comment Request; Draft Supporting Materials for the Science Advisory Board Panel on the Role of Economy-Wide Modeling in U.S. EPA Analysis of Air Regulations, Federal Register Vol. 79, No. 24 (Wednesday, February 5, 2014).

Dear Sir/Madam:

The U.S. Chamber of Commerce, American Chemistry Council, American Forest & Paper Association, and National Lime Association (collectively, the “Associations”) offer these comments on the Environmental Protection Agency’s (“EPA”) Notice on Comment Request; Draft Supporting Materials for the Science Advisory Board Panel on the Role of Economy-Wide Modeling in U.S. EPA Analysis of Air Regulations, 79 F.R. 6899 (February 5, 2014) (“SAB”). As discussed below, the Associations offer the following recommendations on issues that the SAB should consider in its deliberations on the role of economy-wide modeling in EPA air regulation analyses.

The **U.S. Chamber of Commerce** (“Chamber”) is the world’s largest business federation, representing the interests of more than three million businesses and organizations of all sizes, sectors, and regions, as well as state and local chambers and industry associations, and is dedicated to promoting, protecting, and defending America’s free enterprise system.

The **American Chemistry Council** (ACC) represents the leading companies engaged in the business of chemistry. ACC members apply the science of chemistry to make innovative products and services that make people's lives better, healthier and safer. ACC is committed to improved environmental, health and safety performance through Responsible Care®, common sense advocacy designed to address major public policy issues, and health and environmental research and product testing. The business of chemistry is a \$770 billion enterprise and a key element of the nation's economy. It is one of the nation’s largest exporters, accounting for twelve percent of all U.S. exports. Chemistry companies are among the largest investors in research and development. Safety and security have always been primary concerns of ACC members, and they have intensified their efforts, working closely with government agencies to improve security and to defend against any threat to the nation’s critical infrastructure.

The **American Forest & Paper Association** (AF&PA) serves to advance a sustainable U.S. pulp, paper, packaging, and wood products manufacturing industry through fact-based public policy and marketplace advocacy. The forest products industry accounts for approximately 4 percent of the total U.S. manufacturing GDP, manufactures approximately \$210 billion in products annually, and employs nearly 900,000 men and women. The industry meets a payroll of approximately \$50 billion annually and is among the top 10 manufacturing sector employers in 47 states.

The **National Lime Association** (NLA) is the national trade association for manufacturers of high calcium quicklime and dolomitic quicklime (calcium oxide), and hydrated lime (calcium hydroxide), which are collectively and commonly referred to as “lime.” Lime is commonly known as the “versatile chemical.” Lime is used in a broad array of critical applications and industries, including environmental control and protection, metallurgical, construction, chemical and food production. NLA’s members produce greater than 99 percent of the U.S. calcium oxides and hydroxides.

Background

The U.S. Chamber of Commerce has taken the position that whole economy modeling should be the standard modeling tool for EPA Clean Air Act (CAA) regulations in order to more fully and accurately portray the effects of these far-reaching regulatory actions. The Chamber has previously noted that the EPA has too often relied upon partial economy, or partial equilibrium analysis, in its modeling of the economic impacts of CAA regulations.¹ Research has demonstrated how disparate the costs and labor market impacts of rules can be when the effects of regulation outside the directly regulated market are considered versus when they are ignored.

NERA Economic Consulting found in a review of EPA’s methods of estimating employment impacts that properly applying a whole economy model rather than relying on partial economy analysis and outdated, inappropriately applied empirical studies resulted in a massive and consistent shift in estimated impacts across examined regulations. For instance, EPA in its Regulatory Impact Analysis (RIA) estimated that the 2011 Mercury and Air Toxics Standard (MATS) rule would create 46,000 temporary construction jobs and 8,000 net new permanent jobs, while application of an economy-wide, multi-sector model found that in fact the rule would actually have negative employment impacts equivalent to 180,000 to 215,000 lost jobs in 2015 tapering to 50,000 to 85,000 annual jobs annually.² Obviously, properly applied economy-wide modeling can make a significant difference in the scope of impacts estimated as well as the accuracy of those impact estimates.

In light of the shortcomings of some recent EPA modeling practices, the Associations welcome the opportunity to offer suggestions to the EPA’s proposed Science Advisory Board

¹ NERA Economic Consulting, “Estimating Employment Impacts of Regulations: A Review of EPA’s Methods for Its Air Rules,” pps. 14-16.

² *Id.* at 26-29.

(SAB) Panel on the use of whole economy models in order to better inform the rulemaking process for EPA CAA rules.

Recommendations

While the Associations appreciate the EPA's efforts in providing an analytical blueprint and charge questions documents for the SAB on using whole economy modeling for rulemaking economic analyses, there are some critical issue areas that EPA's draft documents fail to address either at all or in a sufficient manner. The Associations therefore has a number of additional issues that the SAB should be specifically tasked to address in order to ensure that any future systematic use of economy-wide models for CAA regulation analyses provide the most useful information possible to policymakers.

The Associations' recommendations to the EPA for the SAB panel to consider are outlined below and cover two broad areas. First, recommendations one through six include suggestions for more detailed analytical requirements on the cost side that are important for improving the utility of whole economy models as well as recommendations for ensuring that models produce robust results. Second, recommendations seven and eight present caveats concerning the vast differences in analytical challenges in incorporating costs and benefits into economy-wide models. Costs tend to be certain, expensed in the near term, and accounted for easily via market transactions, and are therefore simpler to include in models and produce sensible outputs. Benefits tend to be uncertain, cover vast potential ranges, are often unrealized for long and indeterminate time periods extending into the future, and are often difficult to verify and measure upon realization, making them exceedingly difficult to incorporate into analytical models of market transactions in ways that produce meaningful outputs.

In particular, EPA should charge the panel to consider the appropriateness and applicability of the operating principles and questions and provide through its "Blueprint" document support materials described below:

1) Economy-wide models should include significant industry sector detail

Any model used for assessing the broad impacts of CAA regulation on the economy should include sufficient detail by industry sector to enable detailed views of both direct and indirect industry impacts. When assessing regulation, the distribution of impacts is as important as the overall impact. While it is important for cost-benefit modeling to capture economy-wide impacts, it should not be accomplished at the expense of reducing the level of modeling detail, such as employment losses and plant shutdowns, regarding highly-impacted industries. The Associations recommend adopting a model with as much detail as possible in terms of both industry sector and labor occupational differentiation, so that transitional adjustment costs can be inferred from the comparison of base case versus post regulation equilibria.

2) Economy-wide models should include significant regional detail

Any adopted model used for assessing economy wide impacts should include sufficient regional detail to identify changes in the regional distribution of output and employment, which may imply relocation adjustment costs imposed on labor and capital.

3) Economy-wide models should include international trade flows

The SAB panel should investigate the inclusion of trade flows to estimate the effects of regulatory costs on US tradable sectors. It is important to note the impacts of regulation on US competitiveness, a key element missing in virtually all partial equilibrium estimates of regulatory impacts and in many general equilibrium impacts estimates. Many industries are more susceptible to employment and production displacements due to fierce foreign competition; when this is the case the magnitude of regulatory compliance costs alone is insufficient to judge the true impact of a regulation.

4) Economy-wide models should employ dynamic analysis of adjustments

The SAB panel should investigate the appropriate dynamic analyses appropriate for examining the short-, medium-, and long-term adjustments required in capital and labor markets when regulations are imposed. Because most whole economy models are equilibrium models, they tend to provide snapshot results of the economy before and after regulatory impacts are fully incorporated into the simulated markets. While instructive, this often glosses over important adjustment effects that may move relevant markets away from equilibrium for extended periods of time. These effects are important to understand and should be an integral part of CAA economy-wide modeling.

5) Economy-wide models should be frequently and consistently validated

The SAB panel should investigate and consider recommending that EPA engage in an ongoing testing and validation exercise for whole economy modeling that includes public comment and participation. Because of the complexity of the models discussed in EPA's analytical blueprint, and their sensitivity to parameterization, ongoing testing and validation should be used to enhance model calibration over time. Additionally, whole economy models should be subjected to thorough sensitivity analysis in order to understand and quantify model robustness with respect to parameterization and specification.

6) EPA should provide the SAB Panel resources for model testing by panel members

Furthermore, the EPA should provide the SAB panel with the resources necessary to experiment with model technologies under consideration, including full access to models, necessary data for calibration, and all other resources necessary to produce model estimates. The Associations believe that the type of calibration and validation analyses

outlined are paramount in establishing the credibility, reliability, and robustness needed for these models to produce useful information for policy formulation.

7) Economy-wide models should be reviewed for validity of inputs, especially with respect to benefits

The SAB panel should carefully evaluate EPA's attempts to add benefits estimates that revolve around non-market impacts into economic models that evaluate the effects of policy on market transactions. Much of EPA's discussion in its analytical blueprint and draft charge questions revolves around incorporating benefits estimates into models, with the agency noting the magnitude of effects in previous model runs. The SAB should carefully investigate the mechanisms by which EPA proposes to include benefits, many of which affect non-market transactions or accrue to individuals through non-traded channels. It is imperative that the channels of transmission for estimates of price and quantity impacts of benefits claims be thoroughly and carefully vetted to ensure that "phantom" benefits do not inflate estimates and thereby short circuit the usefulness of economy-wide models for addressing the appropriateness of policy choices. It would be misleading if, for instance, EPA claimed economic benefits via labor market effects for benefits that would actually accrue only to retired individuals no longer in the labor force. Careful attention to detail in terms of the expected timing of costs and benefits is important to avoid such misleading results.

8) Economy-wide models should be reviewed to ensure that all relevant impacts be included

On a related note to point 7 above, any inclusion of changes to the status quo should be evaluated for effects on both costs and benefits – for example, if avoided medical expenses for premature morbidity and mortality are incorporated into a model as a benefit appropriately valued in a market-based model, then it is incumbent upon the agency to include the full value of changes over the lifecycle of individuals to which the benefits accrue.³

Conclusion

The Associations recommend that the SAB panel take great care to ensure that the cost analysis of any whole economy modeling that the EPA undertakes provides sufficient detail as to be useful in addressing current gaps in knowledge in typical regulatory impact analyses. Specifically, the EPA should be considering the impacts of regulations on industry sectors'

³ For example, if benefits accrue to individuals with compromised health, it is inappropriate to model benefits as if a delay in premature morbidity or mortality saves all relevant medical expenditures. Rather the savings arise from pushing medical expenditures further into the future where at some point expenditures will be realized (possibly more or less than the modeled savings). Incorporating this wrinkle in the modeling of savings to medical expenditures exposes the thorny nature and extreme assumptions that must be made in order to claim these benefits as realized savings in a market-based model.

competitiveness in global trade and the impacts of regulation on employment and how those employment impacts affect specific regional economies that are strongly tied to affected industries. The Associations also recommend that the SAB panel provide strong guidance on the appropriate methodology for incorporating benefits into economy-wide models. Such guidance should outline the care that must be taken in identifying and validating the channels through which benefits impact markets. Finally, EPA should make clear that its charge questions and “Blueprint” materials are not in any way intended to limit or restrict the work of the panel, and that the panel has full freedom to solicit additional input from the public and to incorporate materials of its choosing into its deliberations.

Thank you for the opportunity to participate in this proceeding. If you have any follow up questions regarding these comments, please feel free to reach out to William L. Kovacs, Senior Vice President of Environment, Technology & Regulatory Affairs at the U.S. Chamber of Commerce at (202) 463-5457 or by e-mail: wkovacs@uschamber.com.

American Chemistry Council

American Forest & Paper Association

National Lime Association

U.S. Chamber of Commerce